STATE OF MINNESOTA

BEFORE THE PUBLIC UTILITIES COMMISSION

In the Matter of Minnesota Power's Application for Approval of its 2021-2035 Integrated Resource Plan

PUC Docket No. E015/RP-21-33

CLEAN ENERGY ORGANIZATIONS' INITIAL COMMENTS

On Behalf Of
Fresh Energy
Clean Grid Alliance
Sierra Club
Minnesota Center for Environmental Advocacy

April 28, 2022

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SUMMARY OF ARGUMENT

As society's response to the climate crisis accelerates, Minnesota Power faces the very real prospect of having to entirely decarbonize its power supply between now and 2035 – precisely the term of its proposed 2021 Integrated Resource Plan ("IRP"). However, instead of presenting a flexible plan that could accommodate that goal, the utility's plan would build a new fossil gas plant while failing to retire its final decades-old coal plant. In these two conspicuous ways, this IRP is inconsistent with the public interest under Minnesota law, and the Commission should not approve it without modifications.

These comments are jointly filed by the nonprofit organizations Fresh Energy, Clean Grid Alliance, Sierra Club, and the Minnesota Center for Environmental Advocacy (collectively, the "Clean Energy Organizations," or "CEOs"). They draw upon expert technical analysis by Anna Sommer[1] and Chelsea Hotaling[2] of Energy Futures Group ("EFG"); Matthew Richwine of Telos Energy;[3] Elena Krieger,[4] Karan Shetty,[5] and Kelsey Bilsback[6] of Physicians, Scientists, and

[1] Anna Sommer is a Principal of Energy Futures Group and has supported the CEOs' work on integrated resource planning and related issues before this Commission since 2005.
[2] Chelsea Hotaling is a Consultant with Energy Futures Group and has conducted EnCompass modeling for IRP and certificate of need cases in several states.
[3] Matthew Richwine, B.S., M. Eng. in Power Systems Engineering, is a founding partner of Telos Energy and is a leader in power systems engineering, power electronic controls, and system stability.
[4] Elena Krieger, Ph.D., is the Director of Research at PSE Healthy Energy and has characterized operational, emissions, health, air quality, and environmental justice measures for power plants across the country. She holds a Ph.D. from the Department of Mechanical & Aerospace Engineering at Princeton University, where her research focused on optimizing energy storage in renewable energy systems and an AB in Physics and Astronomy & Astrophysics from Harvard University.
[5] Karan Shetty, M.ESM, is the Clean Energy Transition Analyst at PSE Healthy Energy where he works on energy equity and affordability, air pollution, and health impacts from fossil fuel power. He received his Master's in Environmental Science and Management from UCSB's Bren School, where he specialized in energy, climate, and carbon reductions, as well as strategic environmental communications and his undergraduate degree in Environmental Science from UCLA.
[6] Kelsey Bilsback, Ph.D., is Senior Scientist at PSE Healthy Energy where her work uses atmospheric modeling to evaluate the impacts of energy production and use on air quality and human health. She holds a Ph.D. in Mechanical Engineering and a B.A. in Physics.

Engineers for Healthy Energy; and Tyler Comings[7] and Joshua Castigliego[8] of Applied Economics Clinic. The CEOs additionally collaborated with the Union of Concerned Scientists in the preparation of these comments.

In Part I of these comments, CEOs show that Minnesota Power's IRP is fundamentally inconsistent with the carbon emission cuts needed to keep warming within the globally-agreed target of 1.5°C. Multiple recent studies setting forth pathways for the U.S. to achieve the needed decarbonization exclude all new combined cycle ("CC") gas plants like the proposed Nemadji Trail Energy Center ("NTEC") and retire old coal plants like Boswell by 2030. Minnesota Power's plans for NTEC and Boswell cause Minnesota Power's plan to fail under all five factors the Commission must consider under its resource planning rule.[9]

In Part II, CEOs discuss how the Commission has the authority and duty to determine in this docket whether continued investment in NTEC is in the public interest, yet Minnesota Power has not even attempted to make this showing. A core purpose of Minnesota's utility planning laws is to prevent the financial disasters caused in years past when utilities failed to adapt their power plant investment plans to changing circumstances (Part II.A). The Commission has repeatedly affirmed that prudence demands such adaptation, even when that means cancelling previously approved power plants (Part II.B). The continued pursuit of NTEC is also subject to Commission review under the Affiliated Interest Agreement statute, Minn. Stat. § 216B.48 (Part II.C), and

[7] Tyler Comings is a Senior Researcher at the Applied Economics Clinic. He focuses on energy system planning (including integrated resource plans), costs of regulatory compliance, wholesale electricity markets, utility finance, and economic impact analyses. He has provided testimony on these topics in Arizona, Colorado, the District of Columbia, Hawaii, Indiana, Kentucky, Ohio, Oklahoma, Maryland, Michigan, Missouri, New Jersey, Nova Scotia (Canada), and West Virginia.

[8] Joshua Castigliego is a Researcher and Assistant Director at the Applied Economics Clinic. He has more than four years of professional experience in energy and climate research and analysis, with a focus on decarbonization and pollution mitigation.

[9] Minn. R. 7843.0500, subp. 3.

under the expansive authority provided by Minn. Stat. § 216B.25 (Part II.D). In addition, important changes since the Commission considered NTEC in 2018, including more aggressive climate targets, greater risk that gas investments will be stranded, and Minnesota Power's parent company's decision to sell most of its share of NTEC, warrant an updated consideration of NTEC in this proceeding (Part II.E).

Part III details CEOs' EnCompass modeling, conducted by Energy Futures Group in collaboration with Applied Economics Clinic, which shows that an IRP that excludes NTEC is cost-effective and reduces financial, policy, and climate risk without sacrificing reliability. The CEO Preferred Plan replaces NTEC with more wind, solar, and battery storage resources, and it meets Minnesota Power's own modeled capacity needs and energy needs for all hours of the year throughout the planning period. CEOs' EnCompass modeling shows that the CEO Preferred Plan without NTEC is directly cost-competitive with Minnesota Power's Preferred Plan; indeed, the CEO Preferred Plan is slightly less expensive across several sensitivities, including in the reference scenario in a head-to-head comparison. CEOs' modeling also shows that the Hibbard coal and biomass plant can be retired, which, as we discuss in Section VIII, would deliver substantial public health benefits.

Part IV presents the findings of a detailed transmission reliability analysis, conducted by Telos Energy ("Telos"), which finds that the CEO Preferred Plan results in a no less reliable transmission grid than Minnesota Power's plan. Telos conducted its analysis using the same software modeling tools and underlying electricity system database as Minnesota Power. It found that Boswell unit 3 can retire reliably without NTEC, and that Minnesota Power must begin planning transmission mitigations now to reliably retire Boswell unit 4 by 2035 or sooner.

Part V discusses the broader need to plan for the retirement of Boswell 4. It highlights the failure of Minnesota Power's IRP to develop a plan to retire Boswell 4, despite already being ordered by the Commission to include a plan for the unit's early retirement and despite claiming that its proposed IRP will result in a generation mix that is coal-free by 2035. Part V explains why Minnesota Power must immediately begin planning the transmission upgrades needed to keep available the option of retiring Boswell 4 by 2030.

Part VI discusses how Minnesota's current CO_2 regulatory cost estimates fail to capture the full regulatory risk now faced by coal and gas. The estimates can also obscure true costs when applied – counterintuitively, Minnesota Power's modeling indicates that high carbon regulatory costs make Boswell 3 and 4 more competitive with lower-carbon scenarios rather than less. The Commission should recognize the limitations of current CO_2 regulatory cost estimates when assessing Minnesota Power's IRP and should commence a proceeding to update these estimates as contemplated by statute, along with the rules for their application.[10]

Part VII explores how a resource portfolio with more distributed solar, rather than one that focuses only on utility-scale solar, has the opportunity to be cleaner, be more equitable, create more jobs, and provide cost-effective solar to the system.

Part VIII presents the expert analysis of health and equity issues conducted by Physicians, Scientists, and Engineers for Healthy Energy ("PSE"). CEOs describe the considerable harm to human health that results from continuing to run the Boswell plant, along with the disproportionately large adverse health impact of the Hibbard plant, and the extent to which these harms fall disproportionately on vulnerable populations, especially Native communities. The PSE analysis also shows how factoring in upstream methane emissions dramatically increases NTEC's

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[10] Minn. Stat. § 216H.06.

climate impact. This part of our comments further discusses how Minnesota Power can reduce the energy burden on low-income[11] ratepayers and explains why IRPs should include this sort of human health and equity analysis.

CEOs' recommendations to the Commission are set forth in detail at the end of this document. We respectfully request the Commission to: 1) modify Minnesota Power's Preferred Plan by removing NTEC, ordering the retirement of Hibbard, and finding the need for more solar power; 2) order the retirement of Boswell 3 by the end of 2029 (as proposed by Minnesota Power); 3) order Minnesota Power to commence planning sufficient to maintain the option of retiring Boswell 4 by 2030; 4) order Minnesota Power to work with stakeholders to identify steps needed to avoid foreclosing the ability to operate in alignment with 1.5°C pathways in its next IRP; 5) commence a proceeding to update CO_2 regulatory cost estimates and rules for their use; 6) order Minnesota Power to commence stakeholder outreach to develop a modeling construct that enables the utility to model solar-powered generators connected to the company's distribution grid, take steps to better align distribution and resource planning, and account for local community generation goals for distributed generation in its next IRP; 7) order that Minnesota Power's next IRP analyze public health impacts; and 8) order Minnesota Power to establish a stakeholder group to address equity issues, including disproportionate energy burdens.

[11] For the sake of consistency with utility filings and the PSE report, we used the term "low-income" in this comment. However, when not referring to defined terms, we strive to use "under-resourced" as a preferred term of art based on partner feedback.

I. MINNESOTA POWER'S CONTINUED COMMITMENT TO NTEC AND PLAN TO RUN BOSWELL 4 THROUGH 2035 ARE FUNDAMENTALLY INCOMPATIBLE WITH THE DEEP DECARBONIZATION NEEDED BY 2030 TO AVOID CATASTROPHIC CLIMATE CHANGE AND THUS INCONSISTENT WITH THE PUBLIC INTEREST UNDER STATE LAW

The Commission must assess Minnesota Power's resource plan based on whether it is "consistent with the public interest" under the state's resource planning statute.[12] In the last few years, new scientific findings have made it abundantly clear that deep decarbonization of electric utilities by 2030 is essential to protecting the public interest. Moreover, key to that decarbonization is ceasing the construction of new gas plants now, especially combined-cycle plants, and retiring existing coal plants by 2030. Minnesota Power's failure to drop its ill-advised plan to construct and operate the NTEC gas plant and its intent to continue running the coal-fired Boswell Unit 4 through at least 2035 are thus dangerously inconsistent with the public interest.

A. Changes In Climate Science And Policy In Recent Years Establish The Need For The Power Sector To Decarbonize Much Faster Than Previously Understood.

In late 2018, the Intergovernmental Panel on Climate Change ("IPCC") released a landmark report[13] showing how crucial it is to limit warming to 1.5°C above preindustrial levels, beyond which catastrophic global climate impacts become far more likely.[14] This report also found that to have a reasonable chance of staying within this limit, the world must cut greenhouse gas emissions roughly in half by 2030, go on to achieve net zero emissions by 2050, and then actually achieve net negative emissions in the second half of the century.[15] This demands a far faster rate

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[12] Minn. Stat. § 216B.2422, subd. 2(a).

[13] *Global Warming of 1.5°C: Special Report*: *Summary for Policymakers*, IPCC (2018) *available at* https://www.ipcc.ch/sr15/chapter/spm/ [hereinafter "IPCC 2018"].

[14] *Climate Change 2022: Impacts, Adaptation and Vulnerability: Summary for Policymakers*, IPCC (2022) *available at* https://www.ipcc.ch/report/ar6/wg2/ [hereinafter "IPCC 2022"] (including a recent description of the dangerous and widespread disruptions already unfolding from climate change, and a projection of future impacts).

[15] IPCC 2018, *supra* note 13, at C.1, C.3.

of decarbonization in this decade than regulators or policymakers have ever previously confronted. The report, along with a series of record-setting wildfires and other climate disasters, galvanized the global climate movement and raised the climate crisis to a first-tier political issue worldwide, including in the US.

In the November 2021 Glasgow Climate Pact, the nations of the world formally recognized the need for these deep emission cuts by 2030 in order to limit warming to 1.5°C.[16] The Pact stresses that such cuts require "*accelerated action in this critical decade*," and it calls upon parties to speed up their energy transition by "rapidly scaling up the deployment of clean power generation and energy efficiency measures, [and] accelerating efforts towards the phasedown of unabated coal power…."[17]

In short, the push to decarbonize has intensified as the focus has necessarily shifted from midcentury to 2030 – just 8 years away and well within the span of this IRP. Reflecting this new focus, the U.S. submitted a new Nationally Determined Contribution ("NDC") pledging to cut U.S. emissions by 50-52% below 2005 levels by 2030.[18] The governors of 24 states – including Minnesota – similarly pledged to cut net greenhouse gas emissions at least 50-52% by 2030.[19]

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[16] Glasgow Climate Pact, United Nations Climate Change Conference, at paras. 15,17 (Nov. 13, 2021) [hereinafter "Glasgow Pact"] *available at* https://unfccc.int/documents/310475. The world agreed to pursue efforts to limit warming to 1.5° C in the 2015 Paris Agreement and reaffirmed that goal in the Glasgow Pact. The Glasgow Pact recognizes that "limiting global warming to 1.5 °C requires rapid, deep and sustained reductions in global greenhouse gas emissions, including reducing global carbon dioxide emissions by 45 percent by 2030 relative to the 2010 level and to net zero around mid-century…" *Id*. at para. 17.

[17] *Id*. at paras. 18 (emphasis added), 20.

[18] *Fact Sheet: President Biden Sets 2030 Greenhouse Gas Pollution Reduction Target Aimed at Creating Good-Paying Union Jobs and Securing U.S. Leadership on Clean Energy Technologies*, U.S. White House (Apr. 22, 2021), *available at* https://www.whitehouse.gov/briefing-room/statements-releases/2021/04/22/fact-sheet-president-biden-sets-2030-greenhouse-gas-pollution-reduction-target-aimed-at-creating-good-paying-union-jobs-and-securing-u-s-leadership-on-clean-energy-technologies/ [hereinafter "White House Fact Sheet"].

[19] *U.S. Climate Alliance Commits to Achieve Net-Zero Emissions No Later than 2050*, U.S. Climate Alliance (Apr. 23, 2021) *available at* http://www.usclimatealliance.org/publications/newtargets.

Achieving 100% carbon-pollution-free electricity by 2035 is a key part of meeting the nation's pledge under its NDC.[20] Thus, the U.S. power sector faces the challenge of making far deeper cuts than any other sector by 2030 and faces the prospect of needing to completely decarbonize by 2035, just 8 years after NTEC is currently scheduled to come online.[21]

This "power sector first" approach to economy-wide decarbonization reflects the game-changing and ongoing technological advances in renewable energy and storage (discussed more in Part II.E.2 below), which allow faster and cheaper carbon reductions from the power sector than from other sectors. And other sectors of the economy are expected to decarbonize largely by replacing their own fuel use with electricity, making the power sector the cornerstone of broader decarbonization throughout the economy.

CEOs commend the carbon reductions that Minnesota Power has achieved over the past several years. The utility and its customers are in a far better position now than they would have been if Minnesota Power had not invested in more renewable power and reduced its former 95% dependence on coal. However, Minnesota Power still has a very long way to go, and its Preferred Plan does not match the pace and scale called for by climate science and decarbonization pathways.

B. Pathways To Achieving The Deep Decarbonization Needed By 2030 Exclude New Gas Plants Like NTEC And Retire Coal Plants Like Boswell By 2030.

Since the IPPC's 2018 report, multiple national modeling analyses have been published charting feasible and least-cost pathways to achieving deep decarbonization at the scale and speed needed to preserve a reasonable chance to limit warming to 1.5°C.[22] The studies of most relevance

[20] White House Fact Sheet, *supra* note 18.
[21] Letter from Daniel McCourtney, NTEC Environmental & Land Manager, to Wisconsin Public Service Commission, Docket Nos. 9698-CE-100 and 9698-CE-101, (Jan. 26, 2022).
[22] *See, e.g.,* Robbie Orvis, *A 1.5 Celsius Pathway to Climate Leadership for the United States*, Energy Innovation (Feb. 2021), *available at* https://energyinnovation.org/wp-content/uploads/2021/02/A-1.5-C-Pathway-to-Climate-Leadership-for-The-United-States.pdf [hereinafter "Orvis, 2021"]; Nathan Hultman,

to this proceeding, those that focus on the carbon reductions needed by 2030, preclude projects like NTEC and require existing coal plants like Boswell to come off the grid by 2030.[23] Even studies that focus primarily on achieving net zero by 2050 — taking a slower linear reduction pathway that does not quite make the cuts the IPCC says are needed in the 2020s — call for declines in gas generation by 2030 and drive all or virtually all coal power off the grid by 2030.

A leading modeling study, published by Energy Innovation in February 2021, describes how the nation can cut emissions in half by 2030 economy-wide, consistent with the new U.S. NDC and the IPCC's report.[24] Like other similar studies, it finds that particularly deep emission cuts must come from the power sector. The "linchpin of economywide decarbonization," Energy Innovation finds, is achieving 80% carbon-free electricity in 2030 and 100% in 2035,[25] consistent with the Biden Administration's goal. The analysis states that achieving these cuts "requires not building any new gas plants that lack carbon capture," noting that the U.S. "already has a massive oversupply of gas plants, many of which are likely to become stranded assets, and no reason exists to build more gas plants."[26] It also states that "[e]liminating coal power plant emissions is a critical component of achieving the 2030 emissions reduction target. Our analysis finds that without

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et al., *Charting an Ambitious U.S. NDC of 51% Reductions by 2030*, Univ. Md. Center for Global Sustainability (Mar. 2021), *available at* https://cgs.umd.edu/research-impact/publications/working-paper-charting-ambitious-us-ndc-51-reductions-2030 [hereinafter "Hultman, et al., 2021"]; *2035: The Report: Plummeting Solar, Wind and Battery Costs Can Accelerate our Clean Energy Future*, Goldman School of Public Policy (June 2020), *available at* https://www.2035report.com/electricity/ [hereinafter "2035 Report"]; *2030 Report: Powering America's Clean Economy, A Supplemental Analysis to the 2035 Report*, Goldman School of Public Policy (April 2021), *available at* https://gspp.berkeley.edu/faculty-and-impact/centers/cepp/projects/2030-report-powering-americas-clean-economy [hereinafter "2030 Report"].

[23] Orvis, 2021, *supra* note 22, at 8; Hultman et al., 2021, *supra* note 22, Technical App. at 4; 2035 Report, *supra* note 22, at 20; 2030 Report, *supra* note 22, at 3-4.

[24] Orvis, 2021, *supra* note 22.

[25] *Id*. at 4.

[26] *Id*. at 8.

eliminating coal emissions by 2030, achieving U.S. emissions reductions in line with limiting warming to [1.5°C] is impossible."[27]

A March 2021 study published by the Center for Global Sustainability at the University of Maryland similarly shows how the nation could cut emissions by 51% by 2030.[28] It stresses that "U.S. climate ambition by 2030 hinges fundamentally on the ability to rapidly shift to zero-emissions electricity generation."[29] The pathway it charts requires that by 2025 any new gas plants be built with carbon capture and storage ("CCS"), and it largely eliminates coal power without CCS by 2030.[30]

A 2021 supplement to a major analysis published by the Goldman School of Public Policy at the University of California, Berkeley, focuses directly on electricity and charts a path for reducing power sector greenhouse gas emissions by 80% by the year 2030.[31] Like the other reports, the study excludes new gas plants beyond those already under construction and eliminates all coal power by 2030.[32]

At least three other major new studies published since December of 2020 model pathways to achieving the longer-term goal of net-zero U.S. greenhouse gas emissions economy-wide by 2050.[33] These studies, including one published by the National Academy of Sciences, model somewhat less ambitious pathways than the studies mentioned above because they do not aim for

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[27] *Id*. at 6.
[28] Hultman, et al., 2021, *supra* note 22.
[29] *Id*. at 2.
[30] *Id*. at 2, Technical App. at 4.
[31] 2030 Report, *supra* note 22.
[32] *Id*. at 22.
[33] *Accelerating Decarbonization of the U.S. Energy System*, National Academies of Sciences, Engineering, and Medicine, The National Academies Press (2021) *available at* https://www.nap.edu/catalog/25932/accelerating-decarbonization-of-the-us-energy-system [hereinafter "National Academies"]; James H. Williams, et al., *Carbon-Neutral Pathways for the United States*, AGU Advances (2021) *available at* https://agupubs.onlinelibrary.wiley.com/doi/10.1029/2020AV000284; Eric Larson, et al., *Net Zero America: Potential Pathways, Infrastructure, and Impacts, Interim Report*, Princeton, New Jersey (Oct. 29, 2021), *available at* https://acee.princeton.edu/rapidswitch/projects/net-zero-america-project/.

the roughly 50% emission cuts by 2030 that the IPCC report says are needed.[34] Even so, they all stress the need for aggressive action in the next 10 years, including greatly accelerating the deployment of renewables and energy storage. For example, the National Academies report finds that by 2030 the nation needs to deploy about two to three times existing wind capacity and about four times existing solar capacity, plus add 10-60 GW of new battery storage.[35] The report stresses that the rapid drop in price of all these technologies – between nearly 70 and 90% in just the past decade – has "transformed the economics of decarbonization."[36] Costs for these technologies, particularly solar PV and battery storage, are expected to continue to decline in the future.[37] CEO's modeling in this case used the most recent forecast data available in order to reflect these expectations.

While the pathways identified in these three 2050-focused reports do not involve retiring existing gas plants in this decade, they all present scenarios showing gas generation declining by 2030 and gas plant capacity factors falling.[38] Moreover, they all depend on the aggressive retirement of coal plants. One of these studies, by Princeton researchers, looks at five different pathways to net zero emissions by 2050, and "[i]n all five cost-minimized energy-supply pathways, with a linear decline to net-zero emissions by 2050, coal use is essentially eliminated by 2030."[39] Among the "Key Actions Necessary by 2030" identified in the National Academies report is

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[34] *Recapturing U.S. Leadership on Climate,* Environmental Defense Fund, 13 (Mar. 3, 2021) *available at* https://www.edf.org/climate/recapturing-us-climate-leadership.
[35] National Academies, *supra* note 33, at 75.
[36] *Id.* at 3, 60.
[37] *2021 Electricity ATB Technologies and Data Overview*, National Renewable Energy Laboratory, *available at*: https://atb.nrel.gov/electricity/2021/index.
[38] National Academies, *supra* note 33, at 105 (gas generation declines 10-30% by 2030); Williams et al. at 12, Fig. 7 (showing capacity factors for CCGT units starting to plummet around 2025); Larson et al. at 30, 87 (gas generation declines 2-30% by 2030, except in one of the five scenarios examined, in which renewable energy is constrained and which relies more heavily on carbon capture and storage).
[39] Larson, *supra* note 33, at 27.

"[r]etire as much as 100 percent of installed coal-fired capacity by 2030 (or retrofit with systems to capture ≥90 percent of CO_2 emissions)".[40] The third report analyzes multiple decarbonization pathways, and while the pathways diverge after 2035, it identifies with high confidence particular high-priority actions needed this decade, including coal retirement to reach less than 1% of total U.S. generation by 2030.[41] And these U.S.-focused reports are echoed by a major new global analysis by the International Energy Agency, which finds that achieving the global emission cuts needed to reach net zero by 2050 requires that all advanced nations eliminate coal power without carbon capture technology by 2030.[42]

In sum, a remarkable consensus has emerged around the steps needed by 2030 to preserve the possibility of limiting warming sufficiently to avoid catastrophic global climate changes; specifically, we must stop building new gas plants, and we must retire old coal plants by the end of this decade. Minnesota Power's IRP is conspicuously incompatible with this consensus given its ongoing plans to build NTEC and its failure to plan for Boswell 4's retirement.

C. Minnesota Power's Preferred Plan Minimizes Flexibility While Increasing Risk And Fails Under All Five Factors The Commission Must Consider Under Its Planning Rule.

Minnesota Power's Preferred Plan – to keep investing in and depending on NTEC and Boswell – carries tremendous inherent risk. There is a worldwide effort underway to cut emissions enough to limit warming to 1.5°C, and multiple pathway studies make clear what this means for the power sector. Any utility making long-term plans that ignore this global effort is asking its customers to shoulder an immense risk.

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[40] National Academies, *supra* note 33, at 90.
[41] Williams, *supra* note 33, at 20.
[42] *Net Zero by 2050: A Roadmap for the Global Energy Sector,* International Energy Agency, 116 (Oct. 2021) *available at* https://www.iea.org/reports/net-zero-by-2050.

Minnesota Power's failure to withdraw from NTEC or accelerate the complete retirement of Boswell results in a risky plan that falls short on all five factors the Commission must consider under its IRP rule.[43] Policy and economic changes this decade could well drive the cancellation of NTEC when it is partially constructed, after millions more dollars are spent on the project. If NTEC does come online, it could be forced to run at levels much lower than expected or to close just a few years later. Or it could be forced to install carbon capture technology or convert to hydrogen – both costly alternatives depending on as-yet noncommercial technology and unbuilt infrastructure. As for Boswell, it could be driven to closure by 2030 or sooner, given the importance of coal plant closures to meeting the nation's climate goals. Minnesota Power asserts it will take a decade to build the transmission upgrades needed to replace Boswell 4.[44] If so, the need to close by 2030 could require the utility to rush to replace the energy, capacity, and grid support the plant provides, forcing it to accept costly options it could have avoided with better planning. Ignoring these risks threatens system reliability and rates, the first two factors the Commission must consider under Minn. R. 7843.0500, subp. 3(A) and (B).

Minnesota Power's plan also fails to minimize adverse environmental and socioeconomic impacts under subpart 3(C). The plan does not minimize carbon emissions or the heavy burden that Boswell places on public health which falls disproportionately on vulnerable communities.[45]

Additionally, relying on NTEC and Boswell clearly increases the "risk of adverse effects … from financial, social, and technological factors that the utility cannot control," and constrains rather than enhances "the utility's ability to respond" to changes in those factors, under subparts

[43] Minn. R. 7843.0500, subp. 3.
[44] See Part V.C.
[45] See Part VIII.

3(D) and (E). These factors essentially require that long-term plans account for how the world is changing around them and respond accordingly to protect host communities and ratepayers alike.

II. THE COMMISSION HAS THE AUTHORITY AND RESPONSIBILITY TO DETERMINE IN THIS DOCKET WHETHER CONTINUED INVESTMENT IN THE NEMADJI TRAIL ENERGY CENTER IS IN THE PUBLIC INTEREST, YET MINNESOTA POWER HAS NOT EVEN ATTEMPTED TO MAKE THIS SHOWING

The Commission is required to "approve, reject, or modify the [resource] plan of a public utility . . . consistent with the public interest."[46] The Commission cannot assess whether Minnesota Power's overall resource plan is consistent with the public interest without assessing whether NTEC – the plan's single largest and riskiest new resource investment – is in the public interest. The burden that Minnesota Power bears is particularly evident given the non-renewable nature of NTEC. Under the State's renewable energy preference, Minnesota Power must not only show that continuing to pursue NTEC is in the public interest but that "a renewable energy facility is not in the public interest."[47]

Minnesota Power has submitted a resource plan that fails to assess whether NTEC is in the public interest. This planning process provided an ideal opportunity for Minnesota Power to assess whether a long-term investment in a new carbon-emitting resource makes sense under current conditions. Instead of seizing this opportunity, Minnesota Power chose to treat NTEC as if its future construction was inevitable, despite materially changed circumstances and the fact that construction has not begun. When CEOs asked whether Minnesota Power had done any modeling runs that did not presume NTEC would be built and that allowed the model to compare it to other resources, the company responded that NTEC is an "approved project," that it included NTEC in

[46] Minn. Stat. § 216B.2422, subd. 2(a).
[47] Minn. Stat. § 216B.2422, subd. 4.

the modeling as a "base case resource," and that it "did not conduct IRP modeling runs without the project."[48]

Minnesota Power's choice to lock NTEC into every single one of its modeling runs reveals a troubling lack of investment prudence. Minnesota ratepayers, not private investors, bear the financial risk of the company's share of NTEC and must receive a compelling showing that investing in NTEC makes financial sense today given the unprecedented pressure to decarbonize the power sector and given the advances in carbon-free technology. Protecting ratepayers' interest necessitates a robust inquiry into whether committing millions more to the as-yet unbuilt project is prudent. Minnesota Power's response that it had decided not to look into this urgent question[49] – even while going through a long-term planning process with a full suite of analytic tools – is insufficient.

And yet, Minnesota Power is asking the Commission to find that its resource plan is in the public interest even though it has not considered whether this major, controversial project makes any sense today. Minnesota Power seems to believe that once a major new power plant is approved by the Commission, the utility can ignore emerging concerns that undermine the investment during the four years prior to ever breaking ground for the project, even as background circumstances, the project's construction schedule, and MP's share of the project change. This unreasonable assumption runs afoul of Minnesota's resource planning laws and the Commission's many decisions establishing the opposite principle.

[48] Minnesota Power Response to CEO IR 056, Docket No. E015/RP-21-33 (May 24, 2021).
[49] Indeed, Minnesota Power declined to reassess its modeled investment in NTEC even while its own affiliate was selling most of its ownership stake in NTEC, as discussed more in Part II.E.3.

A. A Core Purpose Of Minnesota's Resource Planning Laws Is To Require Utilities To Monitor Changing Circumstances And Adjust Their Resource Plans In Response.

The need for utilities to revisit their construction plans in light of market and regulatory changes is one of the key objectives of Minnesota's resource planning rules. As noted above, two of the five regulatory criteria that the Commission must consider when assessing a resource plan focus on the threat posed by external "financial, social and technological factors."[50] The first such criterion asks whether the plan enhances the utility's ability to respond to changes in these factors affecting its operations.[51] In its 1990 Statement of Need and Reasonableness ("SONAR") adopting this provision the Commission stated:

> The events of the past 15 to 20 years have demonstrated clearly that utilities are affected by a multitude of supply and demand uncertainties. Planning errors across the United States have translated into billions of dollars of plant disallowances and/or rate increases. It is possible to minimize the effect of planning errors if utility plans remain flexible and respond to changing conditions.[52]

The events the Commission refers to date to the 1970s and 1980s, when U.S. utilities spent huge sums pursuing nuclear and coal plants even after shrinking demand forecasts, skyrocketing costs, growing public opposition, and new regulations made these projects imprudent. Nearly 100 nuclear plants and 75 coal plants had to be canceled, many of which had already been under construction for years, and sunk costs for the canceled nuclear plants alone were in the billions of dollars.[53] Some of these losses were passed on to ratepayers, contributing to the three-fold increase

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[50] Minn. R. 7843.0500, subp. 3 (D)-(E).
[51] Minn. R. 7843.0500, subp. 3(D)("Resource options and resource plans must be evaluated on their ability to . . . (D) enhance a utility's ability to respond to changes in the financial, social, and technological factors affecting its operations").
[52] Statement of Need and Reasonableness, *In the Matter of the Proposed Adoption of Rules Governing the Resource Planning Process for Electric Utilities, Minn. Rules, Parts 7843.0100 to 7843.0600*, Minn. Pub. Utils. Comm'n., Docket No. E-999/R-89-201, 21 (Jan. 19, 1990), [hereinafter "IRP SONAR"], *available at* https://www.revisor.mn.gov/rules/status/rule/R-01617.
[53] *See* Congressional Budget Office, *Financial Condition of the U.S. Electric Utility Industry*, 11-12 (March 1986) *available at* https://www.cbo.gov/sites/default/files/99th-congress-1985-1986/reports/doc10b-entire_1.pdf.

in electric rates between 1972 and 1984; other losses were borne by utilities, causing considerable financial distress within the industry.[54] A 1986 federal analysis of that distress noted that utilities that quickly canceled power plants in response to changing conditions fared better financially than utilities that were slower to cancel plants.[55]

Similarly, Minnesota's IRP rule requires the Commission to assess a resource plan based on the plan's ability to "limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control."[56] The SONAR discusses, by way of example, the risk from factors such as changing public attitudes about nuclear power and the development of new energy technologies.[57] Today's growing understanding of the climate crisis, intensifying opposition to fossil fuels, increasing carbon scrutiny by the private sector and capital markets,[58] and rapid advances in carbon-free technologies all fall squarely within the type of "financial, social, and technological factors" both these rule provisions refer to.

Monitoring and responding to changing circumstances are such core aspects of the resource planning process that the Commission has stressed them multiple times in the standard language it uses in its IRP orders, including in its order approving with modifications Minnesota Power's last IRP:

> The [resource planning] process is iterative because analyzing future energy needs and preparing to meet them is not a static process; strategies for meeting future

[54] *Id*. at 9.
[55]*Id*. at 13-14.
[56] Minn. R. 7843.0500, subp. 3(E).
[57] IRP SONAR, *supra* note 52, at 21.
[58] *See e.g.,* Larry Fink, *2022 Letter to CEOs: The Power of Capitalism* (2022) *available at* https://www.blackrock.com/corporate/investor-relations/larry-fink-ceo-letter. "It's been two years since I wrote that climate risk is investment risk. And in that short period, we have seen a tectonic shift of capital. Sustainable investments have now reached $4 trillion. Actions and ambitions towards decarbonization have also increased. This is just the beginning – the tectonic shift towards sustainable investing is still accelerating. Whether it is capital being deployed into new ventures focused on energy innovation, or capital transferring from traditional indexes into more customized portfolios and products, we will see more money in motion. Every company and every industry will be transformed by the transition to a net zero world. The question is, will you lead, or will you be led?"). *Id*.

> needs are always evolving in response to changes in actual conditions in the service area. When demographics, economics, technologies, or environmental regulations change, so do a utility's resource needs and its strategies for meeting them.[59]

Or as the Department of Commerce put it in the recent Xcel IRP docket, electric utilities are expected "to be aware of current market conditions and to prudently adapt to those conditions rather than blindly pursue a path pre-determined months or years before."[60]

It is important for utilities and their regulators to assess continued construction of power plants even long after construction has begun, as the case law discussed below shows. In this case, construction has not yet even begun for NTEC. According to Wisconsin regulatory filings, Minnesota Power and the other project developers currently plan to commence construction in September 2022, and commercial operation has been delayed until March 2027.[61] Construction may be further delayed by litigation over the project in Wisconsin, or permanently blocked by its outcome.[62] The Commission therefore has the opportunity in this docket to assess the wisdom of continuing to pursue NTEC while the project is still at a preliminary stage.

In short, there is nothing in the planning rule that supports Minnesota Power's choice in this resource plan to ignore the critical question of whether continued pursuit of NTEC is in the public interest. The fact that the project was approved years ago does not give Minnesota Power permission to avoid considering in its current resource planning how the case for the plant has

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[59] Minn. Pub. Utils. Comm'n, *In the Matter of Minnesota Power's 2016-2030 Integrated Resource Plan*, Order Approving Plan with Modifications, Docket No. E-015/RP-15-690, 2-3 (July 18, 2016).
[60] Minnesota Department of Commerce, Division of Energy Resources, *In the Matter of Xcel Energy's 2019-2034 Upper Midwest Integrated Resource Plan*, Initial Comments, Docket No. E002/RP-19-368, 100 (Feb. 11, 2021).
[61] Letter from Daniel McCourtney, NTEC Environmental & Land Manager, to Wisconsin Public Service Commission, Docket Nos. 9698-CE-100 and 9698-CE-101, (Jan. 26, 2022).
[62] The Certificate of Public Convenience and Necessity issued by the Wisconsin Public Service Commission remains on appeal in a case brought by Clean Wisconsin and Sierra Club. Clean Wisconsin v. Pub. Serv. Comm'n of Wisc., Dane County Circuit Court, Docket No. 2020-CV-585 (Feb. 28, 2020).

since eroded. On the contrary, a core goal of resource planning is to encourage utilities, in the words of the Commission's SONAR, to "remain flexible and respond to changing conditions."[63]

B. The Commission Has Repeatedly Reaffirmed A Utility's Obligation To Consider Whether Continued Investment In A Power Plant Is Prudent When Circumstances Have Changed, Including Investments In A Plant Previously Approved By The Commission.

The debate over whether and when a utility should have canceled a proposed power plant often occurs after the fact, when the Commission is faced with a utility's request to recover its financial losses from ratepayers. The Commission's responsibility to establish just and reasonable rates requires it to ensure utilities recover from ratepayers only their prudently incurred costs.[64] While this proceeding is not a rate case, the Commission's decisions regarding investment prudence are directly relevant. Certainly, a utility's plan to make an imprudent investment cannot be considered to be in the public interest under Minn. Stat. § 216B.2422, subds. 2(a) and 4.

The Commission's prudence decisions dating back to at least 1987 establish that utilities must prudently assess not only whether to initiate a power plant project but also the distinct question of whether to keep investing in a project as circumstances change.[65] Moreover, multiple recent decisions establish that this obligation does not vanish just because the initial decision to invest in the project has been granted regulatory approval. In three cases where utilities sought recovery of expenditures for canceled projects, the Commission considered the prudence of both

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[63] IRP SONAR, *supra* note 52, at 21.

[64] Minn. Stat. § 216B.16. The Minnesota Court of Appeals has stated that "prudency of investment is a fundamental consideration in determining whether a utility's proposed rates are just and reasonable." *In Re Petition of Interstate Power Company for Authority to Increase its Rates for Electric Service in Minnesota*, 416 N.W. 2d 800, 806 (Minn. App. 1987).

[65] Minn. Pub. Utils. Comm'n, *In the Matter of the Petition of Interstate Power Company For Authority to Increase its Rates for Electric Service in Minnesota*, Findings of Fact, Conclusions of Law, and Order. Docket No. E-001/GR-86-384 (May 1, 1987). In that case, regarding a canceled nuclear plant, the Commission allowed partial rate recovery of the initial planning costs, which it held to have been prudent, but "costs other than preliminary planning were unnecessary and cannot reasonably be assigned to ratepayers." *Id*. at 17.

the initial decision to pursue the project and the subsequent decision to withdraw from it after circumstances had changed. In all three cases – regarding the Big Stone II coal unit,[66] the Sutherland IV coal unit,[67] and the Prairie Island uprate[68] – the project had received advance approval yet changes in the regulatory and economic landscape later rendered the project contrary to the public interest.

The Commission found in all three cases that the utilities in question had prudently initiated the projects and after circumstances changed, they had prudently withdrawn from them. The Commission allowed the utilities to amortize these costs, repeating the exact same language in each case to explain that disallowing costs prudently incurred in good faith could potentially chill a utility's "diligence in developing resources *and in promptly withdrawing from projects when experience shows that they will no longer serve ratepayers' best interests.*"[69] In the case of Xcel Energy's withdrawal from the planned Prairie Island uprate, on which it had already spent $79 million, the Commission praised the company's timely response to "new realities" and "changed circumstances," indicating that it might view the situation differently if Xcel had "fail[ed] to recognize, react to, and disclose signs of trouble as they developed."[70]

The Commission has also recently assessed a utility's prudence in implementing a project that was not canceled but had enormous cost overruns. Xcel's project extending the life of and

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[66] Minn. Pub. Utils. Comm'n. *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota*, Findings of Fact, Conclusions, and Order, Docket No. E-017/GR-10-239 (April 25, 2011) [hereinafter "Big Stone II Order"].
[67] Minn. Pub. Utils. Comm'n, *In the Matter of the Application of Interstate Power and Light Company for Authority to Increase Rates for Electric Service in Minnesota*, Findings of Fact, Conclusions, and Order, Docket No. E-001/GR-10-276 (Aug. 12, 2011) [hereinafter "Sutherland IV Order"].
[68] Minn. Pub. Utils. Comm'n, *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Findings of Fact, Conclusions, and Order, Docket No. E-002/GR-13-868 (May 8, 2015) [hereinafter "Prairie Island Order"].
[69] Big Stone II Order, *supra* note 66, at 11; Sutherland IV Order, *supra* note 67, at 33; Prairie Island Order, *supra* note 68, at 33 (emphasis added).
[70] Prairie Island Order, *supra* note 68, at 32.

uprating the Monticello nuclear plant ran hundreds of millions of dollars over the original estimate, and the Commission launched a proceeding to investigate whether Xcel had been imprudent in managing the project. The Administrative Law Judge in that proceeding concluded that to satisfy its burden of proof for rate recovery, Xcel had to not only show it was prudent to begin the project but that "all of the subsequent decisions were prudent."[71] The ALJ quoted the testimony of an Xcel witness, who acknowledged that prudence involved asking whether, as circumstances changed, "did the company properly think through what its options were and to what extent did the company respond to those changed circumstances in prudent fashion?"[72] The ALJ, and the Commission, found Xcel's management failed to respond to those changes prudently, and Xcel was ultimately denied a return on the project's cost overruns.[73]

This case law unequivocally shows that whether to commence a power plant project and whether, years later, to continue pursuing it are legally distinct questions. Utilities hoping to pass the enormous costs of a new power plant on to Minnesota ratepayers,[74] therefore, cannot rely on the Commission's initial approval of the plant as a reason to avoid scrutinizing, during the several

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[71] Office of Administrative Hearings, In the Matter of a Commission Investigation into Xcel Energy's Monticello Life Cycle Management/Extended Power Uprate Project and Request for Recovery of Cost Overruns, *Findings of Fact, Conclusions of Law, and Recommendations,* Docket No. E-002/CI-13-754, 34 (Feb. 2, 2015).
[72] *Id*.
[73] Minn. Pub. Utils. Comm'n, *In the Matter of a Commission Investigation into Xcel Energy's Monticello Life Cycle Management/Extended Power Uprate Project and Request for Recovery of Cost Overruns*, Order Finding Imprudence, Denying Return on Cost Overruns, and Establishing LCM/EPU Allocation for Ratemaking Purposes*,* Docket No. E-002/CI-13-754, 3 (May 8, 2015).
[74] Even though the nominal owner of NTEC is Minnesota Power's affiliate, South Shore Energy LLC, Minnesota Power stated in its petition seeking approval of the plant that "Minnesota Power is treating its investment in NTEC as the equivalent of a utility-owned and rate-based asset." Minnesota Power, *In the Matter of Minnesota Power's Petition for Approval of the EnergyForward Resource Package*, Petition for Approval, Docket No. E015/M/AI-17-568, at 6-40 (July 28, 2017) [hereinafter "EnergyForward Petition"]. Moreover, Attachment A to the Commission's order approving NTEC says that the costs approved in that docket will be the "starting point for review in the [future] rate case." Minn. Pub. Utils. Comm'n, *In the Matter of Minnesota Power's Petition for Approval of the EnergyForward Resource Package*, Order Approving Affiliated-Interest Agreements with Conditions, Docket No. E-015/M/AI-17-568, 21 (Jan. 24, 2019) [hereinafter "AIA Approval"].

years between approval and groundbreaking, whether the project remains in the public interest. The Commission's earlier NTEC decision addressed whether it was reasonable in 2018 to pursue a combined cycle plant expected to come online in 2024.[75] The question before the Commission today is whether it is in the public interest in 2022 to keep pursuing a combined cycle plant scheduled to come online in 2027. Minnesota Power is not only asking the Commission to ignore this second question, but the utility itself chose to ignore the question in its IRP and EnCompass modeling. This choice was imprudent given the new realities the plant faces.

Moreover, ample evidence in this docket compels a Commission finding that continuing to pursue NTEC is imprudent and not in the public interest. In addition to the changed circumstances making NTEC inconsistent with the public interest (described in Parts I and II.E), the CEOs' modeling shows that renewable options can reliably and cost-effectively replace NTEC (presented in Parts III and IV).

C. The Affiliated Interest Agreement Statute Gives The Commission Continuing Supervisory Control Over Agreements It Has Approved.

The Commission approved NTEC in 2018 under the affiliate interest agreement (AIA) provisions of Minn. Stat. § 216B.48, but that law does not require that the Commission end its scrutiny of AIAs after initial approval. On the contrary, subdivision 6 specifies that the Commission retains "continuing supervisory control over the terms and conditions of the contracts . . . so far as necessary to protect and promote the public interest."[76]

This continuing supervisory control requirement provides the Commission with direct authority to review NTEC in this IRP. It constitutes authority for the Commission to find that Minnesota Power's AIAs to build and operate NTEC are no longer reasonable and consistent with

[75] AIA Approval, *supra* note 74, at 10.
[76] Minn. Stat. § 216B.48, subd. 6.

the public interest, and to make that finding as soon as that unreasonableness becomes apparent. Waiting until years later in a rate case to disallow unreasonable payments would render meaningless the "continuing supervisory control" requirement. In this way, the law demonstrates a clear preference that the Commission prevent unreasonable expenditures made through AIAs before they are made, rather than disallow them after the fact.

The Commission should exercise its continuing supervisory authority over the NTEC AIAs now, through this IRP. The IRP process gives the Commission the opportunity to analyze fully-modeled resource plans with and without NTEC. (Prior to this proceeding, NTEC has never been assessed in the context of a full IRP, and certainly not under the current economic and policy landscape.[77]) And the IRP statute already imposes upon the Commission the affirmative obligation to determine if NTEC is in the "public interest" – the same standard the Commission must apply in its supervision of an AIA.

Moreover, there was a major change in the contractual arrangements governing NTEC when Minnesota Power's parent company sold more than half its share of the plant to Basin Electric Power Cooperative (discussed more below at Part II.E.3).[78] Despite this change, Minnesota Power has not renegotiated or amended its AIAs with South Shore Energy LLC, nor did it announce whether the sale meant Minnesota Power would be taking a different percentage

[77] In Minnesota Power's 2016-2030 IRP, the utility proposed using a bidding process to add a generic 200-300 MW of gas combined cycle generation. The Commission order approving the plan with modifications allowed Minnesota Power to pursue the bidding process to investigate this option, but it explicitly said this decision "establishes no presumption that any or all of the generation identified in that bidding process will ultimately be approved," and required that the next resource plan "include a full analysis of all alternatives to natural gas." Minn. Pub. Utils. Comm'n, *In the Matter of Minnesota Power's 2016-2030 Integrated Resource Plan*, Order Approving Resource Plan with Modifications, Docket No. E-015/RP-15-690 (July 18, 2016) at 9. However, Minnesota Power sought approval of NTEC under the Affiliated Interest Statute instead of within the context of a full-fledged IRP. EnergyForward Petition, *supra* note 74.

[78] ALLETE, *ALLETE Announces Third Partner in Nemadji Trail Energy Center Project*, (Sept. 28, 2021) *available at*: https://investor.allete.com/news-releases/news-release-details/allete-announces-third-partner-nemadji-trail-energy-center#:~:text=28%2C%202021%2D%2D%20ALLETE%2C%20Inc,Cooperative%20for%20approximately%20%2420%20million%20 [hereinafter "ALLETE Press Release"].

of the plant's energy and capacity. In response to an information request from CEOs asking how much of the energy and capacity the utility currently intends to purchase during the years of the resource plan, Minnesota Power stated that it "anticipates it will be taking 20% of the facility."[79] However, the company also stated that it does not intend to update its Capacity Dedication Agreement[80] and submit it to the Commission for consideration until "all ongoing facility permitting processes are complete."[81]

Minnesota Power's roundabout approach, which would build the plant before the Commission reviews an updated AIA, would prevent the Commission from exercising its "continuing supervisory control" over this AIA before construction, and it is a further reason why the Commission should analyze the NTEC project in this proceeding.

D. The Commission Has Broad Authority To Rescind Or Amend Prior Orders Under Minn. Stat. § 216B.25.

The Legislature has also granted the Commission expansive authority to reassess prior decisions as circumstances change. Minnesota Statutes § 216B.25 allows the Commission to reopen, rescind, or change past Commission orders in the public interest.[82] Revisiting a past decision under Minn. Stat. § 216B.25 does not require that the past decision was in error, nor does it require the presence of extraordinary circumstances. Rather, the Commission's authority extends to all situations where revisiting a past decision is in the public interest.

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[79] Minnesota Power Response to CEO IR 077, Docket No. E015/RP-21-33 (Dec. 13, 2021).
[80] The Capacity Dedication Agreement, one of the approved affiliated interest agreements, says that Minnesota Power is offtaking 50% from the facility. *Id*.
[81] *Id*.
[82] "The commission **may at any time**, on its own motion or upon motion of an interested party, and upon notice to the public utility and after opportunity to be heard, **rescind, alter, or amend any order** fixing rates, tolls, charges, or schedules, or any other order made by the commission, and may reopen any case following the issuance of an order therein, for the taking of further evidence or for any other reason. Any order rescinding, altering, amending, or reopening a prior order shall have the same effect as an original order." Minn. Stat. § 216B.25 (emphasis added).

The plain language of the statute evidences the breadth of the Commission's power: with or without prompting by an interested party, the Commission can change *any* past order, at *any* time.[83] Furthermore, principles of res judicata and collateral estoppel do not apply to the Commission's decision to reopen a past order.[84] Therefore, the previously approved AIAs do not bar the Commission from amending Minnesota Power's resource plan to exclude NTEC. Rather, this IRP presents an opportunity for the Commission to reassess those AIAs, and their waning prudence. Parallel to Minnesota Power's duty to continually reassess the wisdom of its planned investments, the Commission has the authority to benefit from hindsight.[85]

Revisiting a past decision under Minn. Stat. § 216B.25 does not require a finding that the past decision was in error. In *Matter of City of White Bear Lake's Request for an Elec. Util. Serv. Area Change Within Its City Limits* ("*White Bear Lake*"),[86] the City of White Bear Lake asked the Commission to use its § 216.25 powers to revisit the 1975 utility service area map and change the boundaries between two utilities. The Commission refused, and the city appealed.[87] The Court disagreed with the City's contention that the original 1975 service area was in error. However, the Court held that § 216B.25 grants the Commission broad powers to revisit past decisions. The relevant question is not whether the original decision was in error, but whether altering the decision would serve the public interest.[88]

Furthermore, using Minn. Stat. § 216B.25 does not require extraordinary circumstances, only evidence that revisiting the decision is in the public interest. In *White Bear Lake*, the

[83] *Id*.
[84] Minn. Pub. Utils. Comm'n, *In the Matter of the Application of Peoples Nat. Gas Co. for Auth. to Increase Rates for Gas Util. Serv. in Minnesota*, Findings of Fact, Conclusions of Law, and Order, 11 (Feb. 8, 1984).
[85] Minn. Stat. § 216B.25.
[86] 443 N.W.2d 204, 207 (Minn. Ct. App. 1989).
[87] The Commission originally did grant the request, but then reversed itself. *Id*.
[88] *Id*.

Commission also argued that it could not revisit the original service area boundaries absent extraordinary circumstances.[89] The Court of Appeals rejected this argument, observing that § 216B.25 provides the Commission with great flexibility in revising any order at any time.[90] The statute allows the commission to decide anew whether a past decision still serves the public interest, without being bound by past reasoning.

In the past, the Commission has found it appropriate to use § 216B.25 when a petitioner presents new evidence or issues that require further consideration by the Commission. For example, in *In the Matter of Awa Goodhue Wind, LLC's Application for A Certificate of Need*,[91] a project proposer obtained a Certificate of Need for a wind project in 2011. The project was not built on time, and the proposers asked the Commission to allow the Certificate of Need to stand, despite the delay. In 2013, petitioners presented evidence to the Commission that the proposer had sold their interest in the project to an out-of-state company, that the financing and turbine purchase agreements had fallen through, and that the project was clouded by litigation.[92] In light of this evidence, the Commission used its § 216B.25 powers to reopen the Certificate of Need in order to collect more information from the proposers. Ultimately, the Commission decided to allow the Certificate of Need to expire rather than allowing an extension.[93]

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[89] *Id*.
[90] *Id*.
[91] Minn. Pub. Utils Comm'n, *In the Matter of Awa Goodhue Wind, Llcs Application for A Certificate of Need for A 78 Mw Wind Project & Associated Facilities in Goodhue Cty.*, Order Reopening Case Under Minn. Stat. § 216B.25, Setting Procedures, and Requiring Filings, Docket No. IP-6701/CN-09-1186, 2-3 (Mar. 20, 2013).
[92] *Id*.
[93] Minn. Pub. Utils Comm'n, *In the Matter of Awa Goodhue Wind, Llcs Application for A Certificate of Need for A 78 Mw Wind Project & Associated Facilities in Goodhue Cty.*, Order Accepting Withdrawal, Revoking Site Permit, and Closing Dockets, Docket No. IP-6701/CN-09-1186, 2-3
(Oct. 23, 2013).

The Commission has also used its § 216B.25 powers to reopen matters when new regulatory and economic circumstances have undermined the prudence of the past decision. For example, in *Matter of Petition of Minnesota Power & Light Co.*,[94] Minnesota Power & Light made a deal to sell its interest in Boswell 3 to Northern States Power. In light of that deal, Minnesota Power was allowed to use the accounting mechanism "allowance-for-plant-being-phased-out" ("AFPO"). After that allowance, circumstances changed. Litigation and regulatory changes cast doubt over whether the sale would go through. Considering the changed circumstances, the Commission reopened and amended its accounting treatment of the AFPO credit.[95] CEOs have similarly presented compelling evidence of changed circumstances in this docket, discussed in Part II.E below, that cast a shadow on the prudence of Minnesota Power's investment in NTEC.

Thus, the Commission is not bound to approve the current plan, including NTEC, in the name of consistency with the AIAs. Section 216B.25 stands as additional evidence that the Legislature trusts the Commission to change decisions that no longer serve the public interest. Since the Commission is already obliged to assess this IRP according to a public interest standard under the planning laws,[96] § 216B.25 may be seen as additional authority the Commission can exercise in this docket to modify Minnesota Power's plan by excluding NTEC.[97]

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[94] Minn. Pub. Utils. Comm'n, *In the Matter of the Petition of Minnesota Power and Light Company, d/b/a Minnesota Power, for Authority to Change its Schedule of Rates for Retail Electric Service in Minnesota*, Order Approving and Clarifying AFPO Agreement, No. E-015/GR-87-223 (Sept. 8, 1989).
[95] *Id*. at 9.
[96] Minn. Stat. § 216B.2422, subds. 2, 4.
[97] The notice and opportunity to be heard requirements of § 216B.25 have already been satisfied in this docket. Minnesota Power had ample notice that its plan, including continued pursuit of NTEC, would be assessed based on whether it is "consistent with the public interest" under § 216B.2422. It had every opportunity to show that continued pursuit of NTEC was in the public interest, but it chose not to try to make that showing. Moreover, Minnesota Power has an opportunity to file a reply to this comment.

E. Circumstances Have Changed Dramatically Since NTEC Was Approved In 2018.

There have been major changes since 2018 relevant to the reasonableness of building NTEC. As Xcel Energy acknowledged in a recent IRP filing in which it explained why its previously-planned and legislatively-enabled Sherco combined cycle gas plant was no longer in the ratepayers' best interest, "the industry is currently in the midst of particularly accelerated change and to say the landscape is evolving quickly would be an understatement."[98] In fact, the industry is in the midst of an unprecedented transformation – a process of decarbonization that will only intensify in the years immediately ahead, as the industry is pushed to respond to what the Glasgow Pact called the need for "accelerated action in this critical decade."[99]

Moreover, given ongoing technological advances in carbon-free energy, combined cycle plants face a growing threat of becoming stranded investments. Indeed, Minnesota Power has already decided it wants much less of NTEC and its output than it wanted in 2018, effectively admitting that circumstances affecting NTEC have changed while failing to reflect that change in its IRP modeling or filing.

1. It is far more evident now than in 2018 that new gas plants are incompatible with the carbon cuts needed by 2030, especially when considering lifecycle emissions.

When the Commission voted 3-2 to approve the NTEC project in October of 2018, the need to stop building new gas plants like NTEC was far less evident than it is today. The IPCC 1.5°C Report had just been released earlier that month,[100] and its findings and their sweeping implications were not part of the record. Policymakers generally were not aware of the need to cut

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[98] Minn. Pub. Utils. Comm'n, *In the Matter of Xcel Energy's 2019-2034 Upper Midwest Integrated Resource Plan*, Xcel Energy Reply Comments, Docket No. E002/RP-19-368, 95 (June 25, 2021).
[99] Glasgow Pact, *supra* note 15, Part IV ¶ 18.
[100] IPCC 2018, *supra* note 12.

greenhouse gas emissions roughly in half by 2030. Policymakers also were not yet aware of the need to achieve roughly 80% decarbonization from the power sector by 2030 and approach complete decarbonization of the power sector by 2035, as the multiple pathway studies discussed in Part I establish and as the Biden Administration has endorsed. And the pathway studies had not yet firmly established the importance of stopping the construction of new gas plants lacking carbon capture if we hope to meet the 1.5°C target.

The record on which the Commission approved NTEC in 2018 also did not reflect recent advances in our scientific understanding of the damage caused by upstream methane emissions associated with gas production and transmission (an issue discussed more in Part VII.C.3). The Commission recently acknowledged the importance of upstream methane emissions when it ordered Xcel to include information about them in its annual performance-based ratemaking reports.[101] And the recently-adopted Natural Gas Innovation Act requires the Commission to consider upstream methane emissions when comparing gas consumption to alternative energy options.[102] The additional climate impact caused by upstream methane leakage matters; the attached PSE Report finds that including lifecycle methane emissions in addition to direct CO_2 emissions increases NTEC's climate impact by 92% over a 20-year time period.[103] The science, modeling, policies, and politics around climate change, around the power sector, and around gas plants are therefore undeniably different than they were in 2018. This alone undermines any contention that the question of whether continued pursuit of NTEC is in the public interest can be ignored in this proceeding.

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[101] Minn. Pub. Utils. Comm'n, *In the Matter of a Commission Investigation to Identify and Develop Performance Metrics and, Potentially, Incentives for Xcel Energy's Electric Utility Operations*, Order Accepting Report and Setting Additional Requirements, Docket No. E-002/CI-17-401, 5 (Feb. 9, 2022).
[102] Minn. Stat. § 216B.2427, subd. 2(a)(3).
[103] PSE Report at Section 3.4.

2. Investments in combined cycle gas plants are already at risk of being stranded, and that risk keeps growing.

The financial case for combined cycle plants like NTEC has eroded substantially since the plant's initial approval, largely due to cost and performance advances by renewable energy and batteries. Major new analyses show that many existing CC plants in the U.S. already face the prospect of early closure, unable to recover even their *operating* costs in the energy market, let alone their initial investment costs. Economic trends mean these financial risks will persist even without new decarbonization policies. It is not surprising, therefore, that over half of proposed CC plants scheduled to come online in 2019 and 2020 were canceled prior to construction.[104] As it happens, the Commission's 2018 vote on NTEC occurred at the very peak of the recent gas rush, with new CC capacity additions plummeting from 22 GW in 2018 to only 9 GW in 2019 and 4 GW in the first nine months of 2021.[105]

Three analyses of recent and projected U.S. investment in gas plants, all published in 2021, spotlight the growing financial hazards faced by these investments, especially for CC plants. The newest, from Rocky Mountain Institute ("RMI"), presents the results of extensive modeling comparing the costs and benefits of nearly every proposed gas plant in the U.S. with a clean energy portfolio (combining renewables, storage, demand response, and energy efficiency) that could provide the same grid services.[106] The RMI analysis finds in its base case analysis, which uses conservative assumptions about both renewable energy costs and gas costs, that 90% of proposed CCs could be economically avoided using clean energy portfolios.[107] If renewable energy prices

[104] Lauren Shwisberg, et al., *Headwinds for US Natural Gas Power: 2021 Update on the Growing Market for Clean Energy Portfolios*, Rocky Mountain Institute, 14 (Dec. 2021), *available at* https://rmi.org/report-release-headwinds-for-us-gas-power/ [hereinafter "RMI Report"].
[105] *Id*. at 13.
[106] *Id*. at 3.
[107] *Id*. at 26.

fall at a somewhat faster rate than the base case assumes (more comparable to price declines in recent years) or if projected gas prices are 22% higher, clean energy portfolios outcompete 96-98% of the proposed CCs.[108]

However, the economic risk is not merely that better and cleaner investments could have been made; it is that just the operating costs of proposed CC plants will exceed the full levelized costs of building new clean energy alternatives, forcing the plants to either operate at a loss or retire years early and making it impossible to recover the initial investment in them in energy markets.[109] Another analysis, published in October 2021 by the financial think tank Carbon Tracker, similarly highlights this risk. It bluntly warns that *all* of the gas plants planned in the unregulated grid areas of the U.S. "will be unable to recover original investment, even if allowed to run for full planned lifetimes," putting some $24 billion at risk.[110] The Carbon Tracker analysis focuses on unregulated markets because it is aimed at private investors, but its warnings are clearly relevant to regulators assessing the prudence of new gas investments by regulated utilities.

Indeed, it appears that many of the gas plants in service in the U.S. are already operating at a loss, unable to compete with renewables in the market. The Carbon Tracker analysis finds that 31% of gas plant capacity operating in the U.S. "is already unprofitable to operate according to our models."[111] A third analysis published in August 2021 by S&P Global Market Intelligence

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[108] *Id*. at 34-35.
[109] *Id.* at 44.
[110] J. Sims, et al., *Put Gas on Standby: Unabated gas plants' future role in the power system should be predominantly limited to backup reserve to allow for flexible low carbon forms of supply to fully emerge*, Carbon Tracker, 3 (Oct. 2021), *available at* https://carbontracker.org/reports/put-gas-on-standby/ [hereinafter "Carbon Tracker Report."].
[111] *Id*. at 22.

warns that some $34 billion worth of U.S. investment in recently-built combined cycle gas plants is already at risk of being stranded.[112]

None of these risk assessments reflects any costs from future assumed decarbonization policies; rather, they are based on current policies and market conditions.[113] More aggressive decarbonization policies – either new restrictions on carbon or additional support for carbon-free alternatives – would amplify the financial risk faced by gas plants.

These analyses do reflect the enormous long-term cost reductions of wind, solar, and batteries, which have already fundamentally transformed power-sector economics. Since 2009, solar photovoltaic ("PV") panel costs have fallen 90% and wind turbine costs have dropped 71%; just since 2013 battery costs have fallen 80%.[114] Long-term cost reductions in these technologies are expected to continue even without new policies as, for example, wind turbines get larger and more efficient,[115] and as solar power and batteries continue to evolve.

And there may well be major breakthroughs in battery technology, like the iron-based batteries being developed by Form Energy. That breakthrough is expected to extend battery life from a typical 4-6 hours today to a game-changing 100 hours, with aims of reaching deployment at a fraction of the cost of today's lithium-ion batteries.[116] The first commercial deployment of this new battery, at a site in Minnesota, is expected to be complete by the end of 2023.[117]

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[112] Adam Wilson & Steve Piper, *A nationwide push for green energy could strand $68B in coal, gas assets*, S&P Global Market Intelligence, 2 (Sept. 6, 2021), *available at* https://www.mncenter.org/sites/default/files/permalinks/A_nationwide_push_for_green_energy_coul...pdf [hereinafter, "S&P Report"].
[113] RMI Report at 30 (listing six economic and policy risks, but not including carbon policies); Carbon Tracker Report at 24; S&P Report at 9.
[114] Orvis, 2021 at 1 (citing cost figures from Lazard and Bloomberg NEF).
[115] Ryan Wiser, et al., *Expert elicitation survey predicts 37% to 49% declines in wind energy costs by 2050,* Nature Energy, 559 (May 2021), *available at* https://www.nature.com/articles/s41560-021-00810-z.
[116] Russell Gold, *Startup Claims Breakthrough in Long-Duration Batteries*, Wall Street Journal (July 22, 2021), *available at* https://www.wsj.com/articles/startup-claims-breakthrough-in-long-duration-batteries-11626946330.
[117] Great River Energy, *Long-duration battery project in the works* (June 17, 2020), *available at* https://greatriverenergy.com/long-duration-battery-project-in-the-works/.

There have been recent interruptions in the long-term trend of falling costs for renewables and storage, though these cost challenges must be viewed in light of the extreme price volatility in gas prices in 2021 and 2022 and impacts on all segments of energy generation.[118] Continued U.S. export growth in liquified natural gas ("LNG") can be expected to continue to put upward pressure on domestic natural gas prices.[119] Despite the recent increase in renewable costs in some places, the fundamental forces driving the long-term decline in the costs of these technologies, including technological advances and economies of scale, should be expected to continue.[120]

And, governments around the world, including the Biden Administration, are getting far more aggressive in pushing for ways to reduce the costs of renewable energy and storage. The U.S. Department of Energy ("DOE") has launched a program to drive the cost of long-duration storage down by 90% below the cost of today's lithium-ion batteries by 2030, directing the experts at its national laboratories to focus on the challenge.[121] The DOE is also working to cut utility-scale solar power costs even further, down to 2.0 cents/kWh by 2030.[122] Expanding support for research and deployment of clean technologies faces fewer political barriers than direct efforts to regulate carbon emissions, as shown by last year's infrastructure bill which makes a historic federal investment in clean energy, including by expanding transmission and improving the battery supply

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[118] *See* Energy Information Administration, Henry Hub Natural Gas Prices, *available at* https://www.eia.gov/naturalgas/weekly/#tabs-prices-1.

[119] Marwa Rashad, *U.S. LNG exporters emerge as big winners of Europe natgas crisis*, Reuters (March 9, 2022) *available at* https://www.reuters.com/business/energy/us-lng-exporters-emerge-big-winners-europe-natgas-crisis-2022-03-09/.

[120] *See* National Renewable Energy Laboratory Annual Technology Baseline (NREL ATB), *available at* https://atb.nrel.gov/electricity/2021/index.

[121] Brad Plumer, *Energy Department Targets Vastly Cheaper Batteries to Clean Up the Grid*, New York Times (July 14, 2021), *available at* https://www.nytimes.com/2021/07/14/climate/renewable-energy-batteries.html.

[122] U.S. Department of Energy, *Investing in a Clean Energy Future: Solar Energy Research, Deployment, and Workforce Priorities*, Issue Brief, 4 (Aug. 2021) *available at* https://www.energy.gov/sites/default/files/2021-08/investing-in-a-clean-energy-future-solar-energy.pdf [hereinafter "DOE Issue Brief"].

chain.[123] Thus, even if more ambitious carbon regulations are delayed, we can expect the intensifying focus on advancing renewables and storage by both governments and markets to further undercut the economics of new gas plants.

Even with Minnesota Power now owning only 20% of NTEC, it still faces significant risk if the plant is forced to retire early. If, for example, NTEC has to retire by 2035 (in compliance with Biden administration's announced goal of a carbon-free grid by that year), the EFG Report shows that **[TRADE SECRET BEGINS…** …**TRADE SECRET ENDS]** of Minnesota Power's investment in NTEC would be stranded.[124] And it is unreasonable to assume this loss could be avoided by retrofitting the plant to capture its carbon or to burn hydrogen. Both options are largely theoretical at this point, but would be quite costly, and those costs have not been reflected in Minnesota Power's modeling of NTEC. Moreover, both options would require the construction of entirely new systems of infrastructure – to carry away and sequester the CO2 or to make and deliver the hydrogen.

The risk that Minnesota ratepayers will suffer losses if NTEC cannot economically compete is made even greater by the fact that it will now be owned by three separate utilities, each in a different state and subject to different state regulatory authorities. This could limit Minnesota Power's ability to respond to the changing economics around gas generation and effectively cut its losses. As the Commission has seen regarding Otter Tail Power's co-ownership of the Big Stone and Coyote plants, when a Minnesota utility commits to a plant that is co-owned with utilities in different states, it can constrain the utility's and this Commission's ability to determine how much

[123] White House, *Fact Sheet: The Bipartisan Infrastructure Deal Boosts Clean Energy Jobs, Strengthens Resilience, and Advances Environmental Justice* (Nov. 08, 2021) a*vailable at* https://www.whitehouse.gov/briefing-room/statements-releases/2021/11/08/fact-sheet-the-bipartisan-infrastructure-deal-boosts-clean-energy-jobs-strengthens-resilience-and-advances-environmental-justice/ [hereinafter, White House Infrastructure Fact Sheet].
[124] EFG Report, Technical Appendix. This estimate assumes NTEC begins operation in 2027.

the plant should run and when it should be retired. [125] This puts Minnesota ratepayers at extra risk of having to continue to pay for power that is both uneconomic and inconsistent with Minnesota's environmental goals.

3. The sale of most of Minnesota Power's share of NTEC is a substantial change since 2018, and it undermines the modeling on which MP's plan is based.

In its September deal with Basin Electric Power Cooperative, Minnesota Power's affiliate South Shore Energy LLC reduced its ownership share of NTEC from 50% to 20%.[126] In other words, whereas Minnesota Power and its parent, Allete, considered 50% ownership of NTEC to be attractive a few years ago, they no longer do. The arguments they used to convince the Commission to approve a 50% stake in the plant are no longer convincing to Minnesota Power and its affiliates themselves. And Minnesota Power stated in its response to CEOs' information request that, while it is delaying renegotiation of its AIAs regarding NTEC, it currently intends to take only 20% of NTEC's output, rather than 50%.[127] In other words, the economic case supporting NTEC has changed so much that Allete now wants to own much less of it, and Minnesota Power intends to use much less of its capacity and energy.

This strongly suggests that Minnesota Power and Allete have been internally reassessing the value of NTEC, and they decided it is of less value to them. We commend this reconsideration, which prudent utilities must do when circumstances change. However, Minnesota Power nowhere acknowledges this change in its IRP, or explains why it still believes it is prudent to commit to buying 20% of the project's energy and capacity rather than none of it.

[125] *In the Matter of an Investigation into Self-Commitment and Self-Scheduling of Large Baseload Generation Facilities,* Minn. Pub. Utils. Comm'n, Docket No. E999/CI-19-704.
[126] ALLETE Press Release, *supra* note 78.
[127] Minnesota Power Response to CEO IR 077, Docket No. E015/RP-21-33 (Dec. 13, 2021).

It is troubling to note that this change was in no way informed by Minnesota Power's EnCompass modeling. According to its responses to CEOs' information requests, Minnesota Power did not conduct any modeling runs that allowed the model to select NTEC (NTEC was forced into the model's selected plan), nor any that considered allowing the model to purchase less than 50% of NTEC's output.[128] This raises a threshold question of why such a major resource decision was not informed by Minnesota Power's resource planning modeling, or indeed by this ongoing resource planning proceeding. What is the purpose of this tool and this planning process if not to inform such major resource choices?

Clearly, the modeling Minnesota Power has presented to support its IRP no longer represents reality or its current intentions. As such, its modeling should not be used as a basis for approving Minnesota Power's IRP, at least with respect to NTEC, and the Commission's previous decision approving NTEC cannot substitute for Minnesota Power's and the Commission's obligation to examine the reasonableness of the project under current circumstances.

III. CEOS' ENCOMPASS MODELING SHOWS THAT CEOS' PLAN WITHOUT NTEC IS A BETTER OPTION THAN MINNESOTA POWER'S PREFERRED PLAN

CEOs' EnCompass modeling, which is based on the Company's modeling but uses updated information and corrections to flaws in Minnesota Power's assumptions, found that a generation resource expansion plan without NTEC and with more wind, solar, and battery storage is essentially equivalent in cost to Minnesota Power's Preferred Plan. Moreover, given the financial and policy risks presented by a new combined-cycle gas plant, NTEC's misalignment with national decarbonization pathways, and Minnesota policy preferences, the CEO Preferred Plan – detailed

[128] Minnesota Power Response to CEO IR 056, 071, 075, Docket No. E015/RP-21-33 (May 24, 2021; Oct. 18, 2021; Dec. 13, 2021).

in this section – is more squarely aligned with Minnesota law, policy, and in the public interest than Minnesota Power's Preferred Plan.

CEOs retained Energy Futures Group ("EFG"), with additional support from Applied Economics Clinic, to analyze the Company's EnCompass generation capacity expansion modeling and to conduct additional modeling on CEOs' behalf. Energy Futures Group and Applied Economics Clinic's analysis and findings are provided in a separate report in Attachment 1 ("EFG Report").

To develop the CEO Preferred Plan, our experts undertook a two-step process. First, they analyzed Minnesota Power's EnCompass assumptions and modeling and made changes to them based on updated information and corrected errors. Using these changes and corrections, EFG ran EnCompass to develop an optimal resource plan that meets the same energy and capacity requirements that Minnesota Power modeled. This plan was dispatched against the same 8760 hourly, chronological profile that the Company used in order to demonstrate that load can be met throughout all years of the planning period. That optimal generation resource expansion plan is referred to as the CEO Preferred Plan.

Then, in order to have an apples-to-apples cost comparison, while updating the modeling to reflect Minnesota Power's 20% NTEC share, EFG ran EnCompass to create an optimal plan with CEOs' changes to modeling cost inputs but including specific thermal resources that are in Minnesota Power's Preferred Plan – namely, NTEC and Hibbard. This is referred to as "Revised MP Preferred Plan" and is presented in the report as a fair and reasonable way to compare the CEO Preferred Plan with Minnesota Power's Preferred Plan.

The changes and corrections to Minnesota Power's modeling assumptions are explained in full detail in Section 1 of the EFG Report, and material changes can be summarized as follows:

- **NTEC**. After Minnesota Power filed its resource plan, the Company announced that it had sold a majority of its portion of NTEC, reducing its share from 50% to 20%. While the Company declined to update its modeling to incorporate this change,[129] EFG included Minnesota Power's new ownership and output share in the Revised MP Preferred Plan for purposes of comparison with the CEO Preferred Plan.[130] The CEO Preferred Plan does not include NTEC and therefore allows a comparison of NTEC to other resource options.[131]

- **Retires Hibbard in 2023**. For the CEO Preferred Plan, EFG set Hibbard – a 44 MW coal and biomass plant – to retire at the end of 2023.[132] As described in more detail in Part VIII of these comments, the PSE Report, Attachment 3, found that Hibbard has significant human health impacts and that these impacts are disproportionately affecting low-income and BIPOC populations.[133] Therefore, the CEO Preferred Plan retired the plant as soon as practicable.[134]

- **Solar-Battery Hybrids**. MP's modeling did not include solar-battery hybrids as a resource option. EFG allowed the model to choose solar-battery hybrids as an option in both the CEO Preferred Plan and the Revised MP Preferred Plan scenarios.[135]

- **Wind, Solar, Battery, Energy Efficiency, and Externality Assumptions**. EFG updated a number of inputs for wind, solar, and battery projects that affected the total assumed costs for those resources in the model.[136] These changes include Investment Tax Credit updates,[137] battery storage size options,[138] updated capital cost information,[139] availability of power purchase agreements,[140] and solar locations and capacity factors.[141] For energy efficiency, EFG modeled a higher level of energy efficiency than MP's base case and, unlike the Company, assumed that Minnesota Power's energy efficiency savings will continue beyond 2029.[142] This energy efficiency level was provided by Minnesota Power and based on the state's Demand Side Management Potential Study. Finally, EFG used

[129] EFG at Section 1.1.1.
[130] *Id.* at Section 1.1.1. NTEC was modeled at a 20% ownership share for Minnesota Power in the Revised MP Preferred Plan scenario.
[131] *Id.* at Section 2.
[132] *Id.* at Section 1.1.7.
[133] *See* Part VIII.
[134] *See* EFG at Section 3.2.
[135] *Id.* at Section 1.1.4.5.
[136] *Id.* at Section 1.1.4.
[137] *Id.* at Section 1.1.4.2.
[138] *Id.* at Section 1.1.8.
[139] *Id.* at Section 1.1.4.1.
[140] *Id.* at Section 1.1.4.3.
[141] *Id.* at Section 1.1.4.4.
[142] *Id.* at Section 1.1.6.

Minnesota's "High" value for both pollution externality costs and CO_2 regulatory costs, while Minnesota Power assumed the "mid" costs.[143]

- **Boswell 3 Retirement Transmission Upgrade**. For the Boswell units, Minnesota Power set up the EnCompass modeling with a constraint that required the model to choose a combination of new gas plants and/or large transmission line upgrades when either Boswell 3 or 4 are retired.[144] For example, if the modeled scenario included a Boswell 3 retirement, then EnCompass had to choose between either a large transmission line investment or a new combustion turbine ("CT"). If Boswell 4 were retired, EnCompass would have to select either a transmission upgrade, a CC, or two CTs to replace Boswell 4. Minnesota Power included this constraint to account for reliability issues it believes will need to be addressed when the Boswell units are retired.[145] EFG did not remove this constraint, but modified it based on CEOs' expert Telos Energy's transmission system reliability power systems modeling, which is discussed in more detail below in Part IV. EFG used a lower cost assumption than Minnesota Power for the level of transmission system upgrades that will be required to reliably retire Boswell 3 by 2030.[146] Telos Energy's analysis found that "[r]etirement of Boswell 3 will require some transmission reinforcements, but probably fewer than MP has proposed. Our analysis finds that MP's proposed transmission upgrades like the [**TRADE SECRET BEGINS… … TRADE SECRET ENDS**] would be sufficient mitigation when applied in conjunction with the CEOs' Preferred Plan generation additions."[147] As such, EFG modeled the transmission mitigation cost at the level of Minnesota Power's proposed [**TRADE SECRET BEGINS… … TRADE SECRET ENDS**].[148]

- **Demand Response Modeling Glitch**. Minnesota Power's modeling included a resource option of 100 MW of new demand response ("DR"), which the model selected as an optimal resource in the modeling runs developing the CEO Preferred Plan.[149] However, when examining the hourly dispatch of those modeling runs, EFG found that the DR resource option was not following the operational characteristics that MP developed. Specifically, the resource was violating both the maximum annual energy and the maximum consecutive energy amounts that the DR was supposed to have by operating at over 600 hours per year and for longer than 12 consecutive hours.[150] EFG attempted to

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143 *Id.* at Section 1.1.3.
144 *Id.* at Section 1.1.2.
145 Minnesota Power Response to CEO IR 027, Docket No. E015/RP-21-33 (Apr. 5, 2021). MP states that its analysis shows "a need for power formerly produced locally by dispatchable baseload generators on the Minnesota Power system in Northern Minnesota to be delivered from new sources when BEC units 3-4 are retired. This replacement power can be supplied locally from new dispatchable generation resources or it can be delivered from remote resources on the regional transmission network.")
146 EFG at Section 1.1.2.
147 Telos at Section 7.2.
148 EFG at Section 1.1.2.
149 *Id.* at Section 1.1.10.
150 *Id*.

> correct the issue with the EnCompass model vendor, but currently EnCompass does not have the combination of inputs needed to remedy the issue.[151] EFG therefore removed the DR resource as an option for the CEO modeling, despite EFG's analysis that this type of DR would likely provide benefits to Minnesota Power's system. Instead, EFG replaced the DR that was being selected by the model with a 100 MW 10-hour battery storage resource and 100 MW of wind, both being added in 2030.[152] This choice was made because EFG determined that "[t]hese two resources are comparable projects to add in place of the demand response project, given the timing of when EnCompass tended to dispatch the demand response project as well as the fact that it seemed to prefer a relatively long duration of dispatch."[153]

Using the changes and corrections to Minnesota Power's EnCompass modeling assumptions, EFG developed an optimal resource plan that meets the same energy and capacity requirements that the Company modeled and provides energy to meet Minnesota Power's load for the load shape they provided, which accounts for all hours of the year throughout all years of the planning period. That plan, which we refer to as the CEO Preferred Plan, replaces NTEC, Hibbard, and Boswell 3 with a combination of wind, solar, storage, and energy efficiency, and does not add any new fossil fuel generation. The generation capacity additions in the CEO Preferred Plan through the planning period include 700 MW of solar, 500 MW of wind, 184 MW of 4-hour battery storage, and 100 MW of 10-hour battery storage, as shown in Figure 1.[154] The specific type and timing of generation resources is provided in Table 1.[155]

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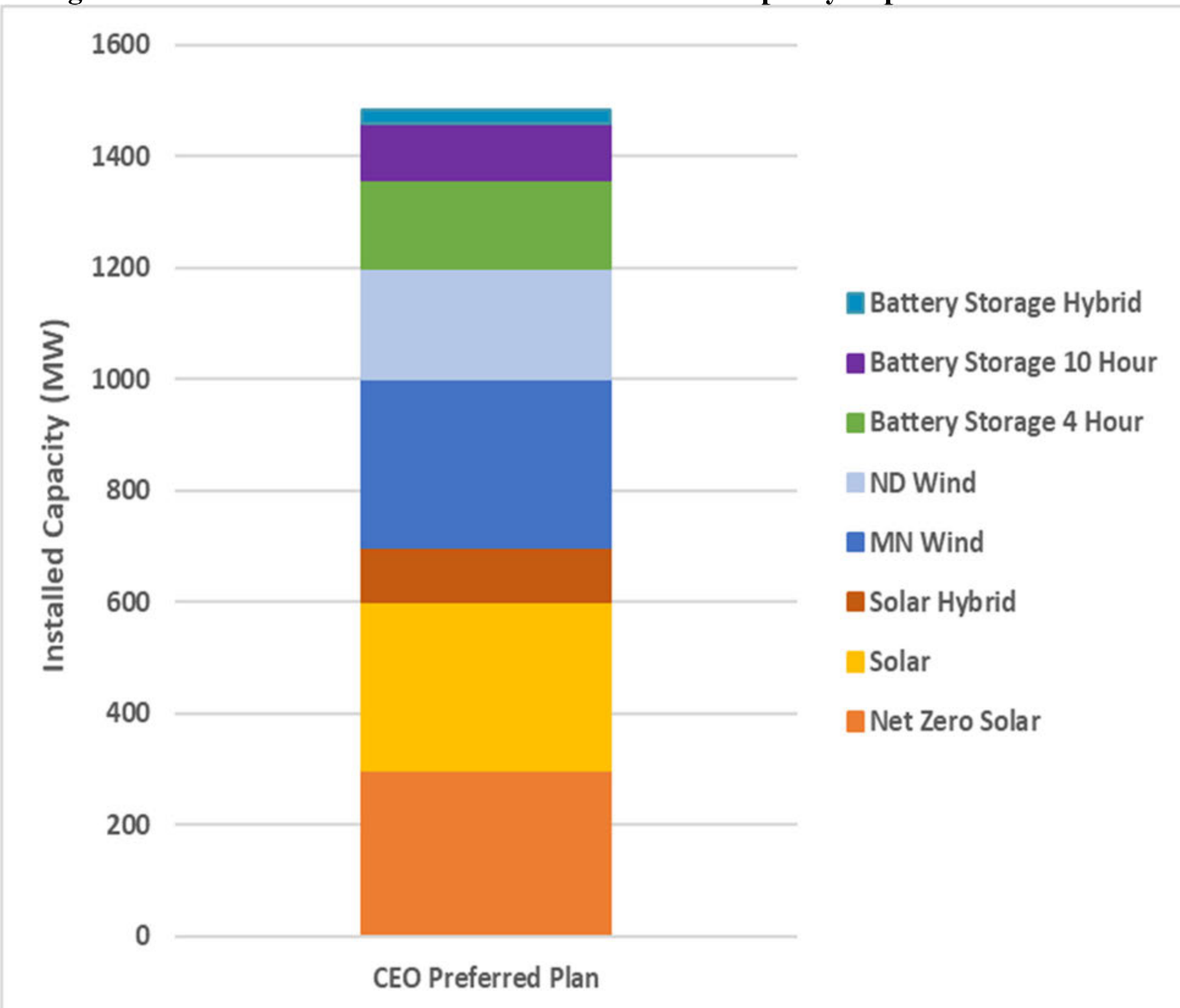
[151] *Id.*
[152] *Id.* at Section 1.1.11.
[153] *Id.* Section 1.1.11.
[154] *See* EFG at Section 3.1.
[155] *Id*.

Figure 1. CEO Preferred Plan Generation Resource Capacity Expansion Additions[156]



[156] *Id*.

Table 1. CEO Preferred Plan Annual Capacity Additions (MW ICAP)[157]

New Resource Additions:	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Net Zero Solar	0	200	100	0	0	0	0	0	0	0	0	0	0
Solar	0	0	300	0	0	0	0	0	0	0	0	0	0
MN Wind	0	0	0	0	0	0	0	200	0	0	0	0	100
ND Wind	0	0	0	0	0	0	100	100	0	0	0	0	0
Battery Storage 4 Hour	0	0	0	0	0	0	0	143	0	0	0	0	16
Battery Storage 10 Hour	0	0	0	0	0	0	0	100	0	0	0	0	0
Solar Hybrid	0	0	0	0	0	0	0	100	0	0	0	0	0
Battery Storage Hybrid	0	0	0	0	0	0	0	25	0	0	0	0	0
Energy Efficiency		2	4	5	7	9	11	11	11	11	11	11	11
Retirements:													
Hibbard	-44												
Boswell 3							-350						

In the near-term (before 2030), the CEO Preferred Plan adds 600 MW of solar and 100 MW of wind. Then, in 2030, once Boswell 3 retires, it adds more wind, stand-alone storage, and solar-battery hybrids. In comparison, Minnesota Power's Preferred Plan's near-term additions are 200 MW of wind, 296 MW of NTEC, and 200 MW of solar when Boswell 3 retires.[158]

Table 2. MP Preferred Plan Annual Capacity Additions (MW ICAP)

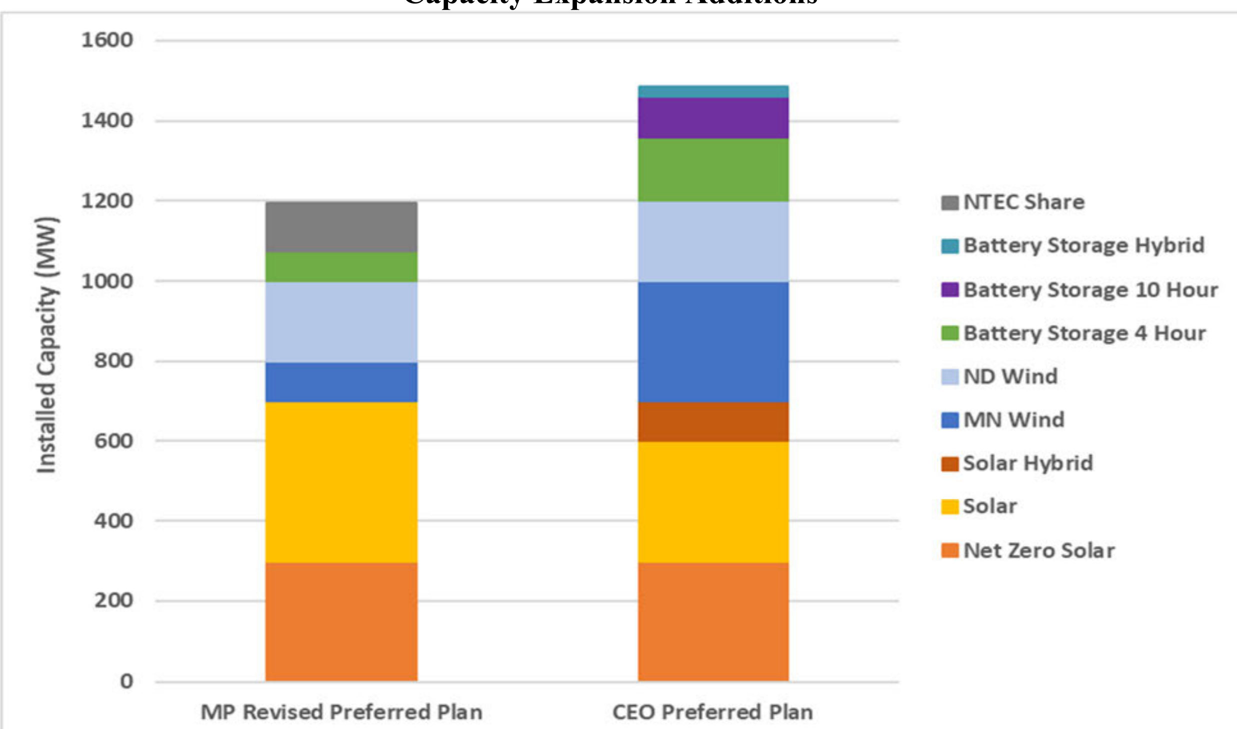
New Resource Additions:	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Net Zero Solar	0	0	0	0	0	0	0	200	0	0	0	0	0
MN Wind	0	0	200	0	0	0	0	0	0	0	0	0	0
NTEC Share	0	0	296	0	0	0	0	0	0	0	0	0	0
Retirements:													
Boswell 3							-350						

[157] *Id*.
[158] Minn. Pub. Utils. Comm'n, Minnesota Power 2021 Integrated Resource Plan, Initial Filing, Docket No. E015/RP-21-33, 66-68 (Feb. 1, 2021) [hereinafter "MP IRP"].

EFG compared the CEO Preferred Plan to the Revised MP Preferred Plan. As a reminder, the Revised MP Preferred Plan is a scenario in which all of the CEO modeling assumption cost and input changes are applied, but key elements of MP's Preferred Plan are included – namely, NTEC (at 20% ownership) and Hibbard. However, because of Hibbard's relatively small size, the overriding difference between the CEO Preferred Plan and the Revised MP Preferred Plan is NTEC. As shown below in Figure 2, the CEO Preferred Plan has more wind, solar, storage and the Revised MP Preferred Plan has fewer of those resources and NTEC.

EFG found that, compared to the Revised MP Preferred Plan, the CEO Preferred Plan has very similar, albeit slightly lower, costs and has fewer CO_2 emissions.[159]

Figure 2. Revised MP Preferred Plan and CEO Preferred Plan Generation Resource Capacity Expansion Additions[160]



[159] EFG at Section 3.2-3.3.
[160] *Id.* at Section 3.1.

This is the apples-to-apples comparison scenario that was developed to more accurately compare costs between the CEO Preferred Plan and the MP Preferred Plan by using the same cost assumptions (such as CEOs' updated solar capital costs), while maintaining the key differences between the plans, particularly MP's inclusion of NTEC. Table 1 shows the costs in both Present Value of Societal Costs ("PVSC"), which includes externality costs, and Present Value of Revenue Requirement ("PVRR"), which does not include externality costs.

Table 3. PVRR and PVSC Results for CEO Modeling ($000) [161]

	Revised MP Preferred Plan	CEO Preferred Plan
PVRR	$6,402,903	$6,391,441
Externality Costs	$1,839,387	$1,849,611
PVSC	**$8,242,290**	**$8,241,052**

The CEO Preferred Plan is cost-equivalent, although marginally less expensive, in the apples-to-apples cost comparison to the Revised MP Preferred Plan. The CEO Preferred Plan also has lower CO_2 emissions than the Revised MP Preferred Plan with NTEC. [162]

Table 4. CO_2 Emission Comparison (Tons)[163]

Year	Revised MP Preferred Plan	CEO Preferred Plan
2021	5,538,719	5,569,799
2022	4,964,703	4,989,758
2023	4,460,408	4,499,462
2024	4,437,314	4,301,762
2025	1,851,215	2,153,912
2026	1,860,234	2,257,351
2027	2,098,749	2,483,209
2028	2,162,244	2,442,054
2029	2,100,623	2,111,941
2030	1,445,283	1,118,664

161 *Id.* at Section 3.2.
162 *Id.* at Section 3.3.
163 *Id.* at Section 3.3.

Year	Revised MP Preferred Plan	CEO Preferred Plan
2031	1,351,279	1,031,120
2032	1,344,305	1,128,925
2033	1,368,242	1,089,725
2034	1,272,580	998,924
2035	1,300,535	962,104
Total	**37,556,432**	**37,138,708**

It is important to recognize that the climate benefits resulting from the CEO Preferred Plan are not fully reflected in the modeled CO_2 emissions. Minnesota Power has projected that the NTEC plant would have a minimum 40-year operating lifetime,[164] meaning that most of its CO_2 emissions would occur after 2035. This table therefore does not reflect most of the CO_2 reductions that come from *not* building NTEC under the CEO Preferred Plan.

The modeled CO_2 emissions also do not reflect the reduction in upstream methane emissions associated with not building NTEC, which the PSE report estimates would increase NTEC's climate impact by 92% over a twenty-year timeframe.[165] The Department of Commerce has rightly pointed out that these additional methane impacts should be considered in IRP analyses,[166] and as we noted in Part II.E.1, the importance of upstream methane emissions is now reflected in the lifecycle focus of the state's Natural Gas Innovation Act.[167] If NTEC's upstream methane emissions, along with the facility's emissions of nitrous oxide (another greenhouse gas), were accounted for, the total CO_2-equivalent emissions for NTEC would rise from 2.24 million to 4.8 million tons CO_2e annually when considering a 20-year horizon for methane. Assuming 20% ownership, Minnesota Power's NTEC share would be 960,000 tons CO_2e per year rather than the

[164] Minnesota Power's Response to DOC IR 001, Minn. Pub. Utils Comm'n, Docket No. E015/RP-21-33.
[165] PSE Report at Section 3.4.
[166] Comments of the Deputy Comm'ner, Minn. Dep't of Commerce, Div. of Energy Resources, Minn. Pub. Utils. Comm'n, Docket No. 19-369 (Feb. 11, 2021).
[167] Minn. Stat. § 216B.2427, subd. 2(a)(3).

448,000 tons CO_2e captured in the model.[168] If we multiply the difference (512,000 tons) by the years NTEC would operate, that represents over 5 million tons of additional CO_2e just during the scope of this IRP, and over 20 million tons of additional CO_2e if NTEC were to operate its intended 40-year lifetime. The PVSC of the Revised MP Preferred Plan would also increase commensurately.

Moreover, as discussed in Part V, keeping a 2030 retirement date for Boswell 4 as a future option is an important outcome of this resource plan. However, the CEO Preferred Plan does not model the early retirement of Boswell 4, because Minnesota Power does not model beyond 2035 and, therefore, does not develop a replacement portfolio for a 2035 Boswell 4 retirement date. If CEOs were to have modeled Boswell 4's retirement when Minnesota Power has not, it would prevent an apples-to-apples comparison that isolates the question of whether NTEC is in the public interest, which is the most imminent resource planning question facing Minnesota Power and the Commission.

EFG also performed sensitivity analyses on the CEO Preferred Plan to test MP's low load, high load, low gas price, high gas price, and higher gas price sensitivities.[169] Under these sensitivities, EFG redispatched both the CEO Preferred Plan and the Revised MP Preferred Plan (which includes NTEC at 20% ownership and Hibbard), in order to compare the resource expansion plans' costs in the different conditions.[170] As shown in Table 5, across all the sensitivities, the CEO Preferred Plan performs as well as the Revised MP Preferred Plan, with the CEO Preferred Plan slightly less expensive in three sensitivities and only marginally more

[168] PSE Report at Section 3.4.
[169] EFG at Section 3.4.
[170] *Id*.

expensive in two. This demonstrates that the CEO Preferred Plan is robust under varying conditions.

Table 5. PVRR and PVSC NPV Results for MP Defined Sensitivities ($000)

Revised MP Preferred Plan ($000)					
	Higher Gas	High Gas	Low Gas	High Load	Low Load
PVRR	$6,559,049	$6,507,445	$6,412,047	$6,729,602	$6,212,887
Externality	$1,853,225	$1,835,066	$1,848,781	$2,123,541	$1,659,805
PVSC	$8,412,273	$8,342,511	$8,260,828	$8,853,143	$7,872,691
CEO Preferred Plan ($000)					
	Higher Gas	**High Gas**	**Low Gas**	**High Load**	**Low Load**
PVRR	$6,503,941	$6,473,381	$6,423,085	$6,714,988	$6,197,756
Externality	$1,850,871	$1,851,573	$1,844,640	$2,108,737	$1,677,527
PVSC	$8,354,812	$8,324,955	$8,267,724	$8,823,726	$7,875,283
PVSC % Difference	**-0.68%**	**-0.21%**	**0.08%**	**-0.33%**	**0.03%**

Overall, CEOs' EnCompass modeling shows that the CEO Preferred Plan, which adds wind, solar and storage in place of NTEC and Hibbard, and does not add any new fossil fuel generation, is directly cost-competitive with the Revised MP Preferred Plan and has lower CO_2 emissions. Moreover, when considered in the context of the considerable financial, policy, and climate risk that comes from building a new combined-cycle gas plant, described extensively in previous sections, the CEO Preferred Plan is squarely in the public interest. Specifically, CEOs' EnCompass modeling demonstrates that the Commission should: 1) approve that MP retire Boswell 3 by 2030; 2) remove NTEC from the approved plan; 3) order Hibbard retired as soon as practicable; and 4) find there is a need for approximately 600 MW of solar by 2026.

IV. TELOS ENERGY'S TRANSMISSION RELIABILITY ANALYSIS SHOWS THAT NTEC IS NOT NEEDED ON GRID RELIABILITY GROUNDS

Minnesota Power has emphasized that retiring the Boswell units will require transmission system "mitigations" through new transmission, generation, operations, and/or other grid equipment like synchronous condensers, in order to maintain a stable transmission system in

Northern Minnesota.[171] To ensure that the CEO Preferred Plan will maintain a reliable transmission system given Boswell coal unit retirements, CEOs retained Telos Energy ("Telos") to analyze the transmission system-level reliability issues and solution options when one or both Boswell coal units are retired. Using the same software modeling tools and underlying system database as MISO and Minnesota Power, Telos found that: (1) Boswell 3 can retire reliably without the NTEC combined cycle plant, and (2) Minnesota Power must begin planning now in order to reliably retire Boswell 4 by 2035 or sooner.

As part of its analysis for transitioning from the Boswell units, Minnesota Power requested a MISO Y-2 Study in 2018. Minnesota Power explains that "[m]irroring the standard MISO generator retirement study (Attachment Y) process, the Attachment Y-2 Study was an information-only study of various scenarios to identify reliability issues due to the potential retirement of the BEC units."[172] This MISO Y-2 Study "concluded that robust mitigating solutions would likely need to be built before the retirement of the BEC units could be allowed."[173] To address these issues, CEOs retained Telos to examine transmission system impacts and solutions from retiring the Boswell units and to conduct modeling analysis, using the same approach, software type, and MISO database as those used by MISO in its Attachment Y and Y-2 study reliability analyses.[174] However, Telos' analysis modeled additional scenarios reflecting different regional generation resource additions consistent with the CEO Preferred Plan, including new wind, solar, and storage, and not including new fossil gas additions such as NTEC and the Sherco CC. Telos' full analysis is provided in detail in its "*Transmission Reliability Analysis of Minnesota Power's Integrated Resource Plan*" ("Telos Report" provided as Attachment 2).

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[171] MP IRP, Appendix F at 40.
[172] *Id*. at 43.
[173] *Id*.
[174] Telos (Attachment 2) at Section 2.

Overall, Telos found that a scenario based on the CEO Preferred Plan "results in essentially equal, and often, better reliability" than a scenario based on MP's Preferred Plan.[175] More specifically, Telos' report highlights two central findings:

- **Boswell 3 can retire reliably without the NTEC combined cycle plant**. Telos found that retiring Boswell 3 will require transmission system mitigation solutions but that adding or removing NTEC has a negligible impact on reliability when Boswell 3 is retired. Regarding Boswell 3, Telos found that Minnesota Power's proposed transmission upgrades, like a **[TRADE SECRET BEGINS… … TRADE SECRET ENDS],** would be sufficient mitigation when applied in conjunction with new generation additions in Minnesota that are planned and consistent with the CEO Preferred Plan. Indeed, Telos found that reliability could be maintained with only a portion of the transmission upgrades Minnesota Power proposed, considerably lowering the costs associated with retiring Boswell 3.[176] The addition of NTEC, however, "does not provide a material transmission system-level reliability mitigation benefit and, in fact, creates thermal and voltage issues on MP's system in the vicinity of NTEC in the scenarios analyzed."[177] Therefore, Telos' analysis shows that CEO Preferred Plan without NTEC provides for the same level of transmission system reliability as Minnesota Power's Preferred Plan.

- **Minnesota Power must begin planning now in order to reliably retire Boswell 4 by 2035 or sooner**. Consistent with Minnesota Power's analysis, Telos found that retiring Boswell 4 in addition to Boswell 3 will increase stress on the system such that more extensive transmission mitigations will likely be required than when retiring Unit 3 alone.[178] These mitigations would almost certainly include transmission line additions, such as the current MISO Long Range Transmission Planning Iron Range line and potentially others.[179] However, Telos found that MP's estimates of the extent of the required transmission mitigation solutions are overestimated.[180] A major aspect of MP's overestimation is due to an unreasonably pessimistic assumption regarding power flows between Minnesota Power and Manitoba Hydro during winter peak conditions, which is discussed in more detail below in Part V.C.[181] Options such as contractual or operational solutions to prevent Minnesota Power from exporting maximum system power to Manitoba during Minnesota Power's highest peak times, therefore, could significantly reduce issues when Boswell 4 retires and lower mitigation needs and costs.[182] These types of contractual or operational solutions, in addition to other grid reliability options like synchronous condensers, could play a role in transmission additions as part of an optimal

[175] Telos at Section 5.1.
[176] *Id.* at Section 7.2. As discussed in Section III above, based on Telos' analysis, Energy Futures Group used MP's proposed proxy **[TRADE SECRET BEGINS … …TRADE SECRET ENDS]** as the mitigation for Boswell 3's retirement in its EnCompass modeling for CEOs.
[177] *Id.* at Section 7.1.
[178] *Id.* at Section 7.3.
[179] *Id.* at Section 5.4.
[180] *Id.* at Section 5.4.
[181] *Id.* at Section 6.
[182] *Id.* at Section 6.

> solution set to reliably retire Unit 4. In order to do exactly this type of analysis, as well as begin transmission line and other mitigation solution investments, Telos found that "[p]lanning for mitigations and/or other solutions needs to start now, even to prepare for retirement of Boswell 4 in 2035, and certainly to preserve the option of earlier retirement."[183]

In addition to these core findings, Telos also studied a sensitivity that examined transmission system impacts of converting Boswell unit 3 to a synchronous condenser when it retires.[184] The results of the conversion showed significantly improved voltage support compared to both Minnesota Power's plan and CEOs' plan scenarios. Telos recommends this approach as a solution because of the reliability benefit and relatively low cost of the solution as a conversion utilizing existing grid infrastructure, rather than a fully new asset.[185]

Telos' conclusions that NTEC does not provide any material transmission grid-level reliability benefit in the context of the CEO Preferred Plan or Minnesota Power's Preferred Plan in conjunction with EFG's EnCompass modeling which showed that the CEO Preferred Plan without NTEC is a cost-effective and reliable alternative to Minnesota Power's Plan demonstrate that NTEC is not in the public interest. Moreover, Telos' analysis underscores the urgency for Minnesota Power to meaningfully plan for Boswell 4's retirement.

V. MINNESOTA POWER NEEDS TO BEGIN TO PLAN FOR THE EARLY RETIREMENT OF BOSWELL 4 NOW

A. Minnesota Power's Preferred Plan Lacks Any Steps That Would Enable The Utility To Actually Retire Boswell 4 In 2035, Even Though The Utility Claims It Will Be "Coal-Free" By That Year.

Minnesota Power prominently claims in the cover letter of its resource plan that its "2021 Plan [will]… result in a generation mix that is coal-free by 2035."[186] This claim is repeated several

[183] *Id.* at Section 7.3.
[184] *Id.* at Section 3.3.2.
[185] *Id.* at Section 3.3.2. Telos estimates that converting Boswell 3 to a synchronous condenser would cost between $8-20 million. Telos at Section 3.3.2, n.31.
[186] MP IRP, Cover Letter.

times in the resource plan, including the more specific claim that its Preferred Plan's "concrete steps" include "ceasing coal operations at Minnesota Power's Boswell Energy Unit 4 in 2035."[187] CEOs appreciate that Minnesota Power recognizes the need to retire Boswell 4. However, aiming for a 2035 Boswell 4 retirement date would still put Minnesota Power on a coal-retirement schedule five years behind where it needs to be for alignment with 1.5°C pathways. Moreover, Minnesota Power's plan does not actually achieve this 2035 retirement.

When CEOs requested that Minnesota Power identify the steps included in its Preferred Plan that would allow Minnesota Power to actually retire or refuel Boswell 4 by 2035, the utility could not identify a single one.[188] In other words, Minnesota Power's plan does not include the construction or purchase of any generation, transmission, or grid-strengthening resources that would allow Minnesota Power to replace the energy, capacity, or reliability services provided by Boswell 4. Minnesota Power stated in its response to CEOs that "[p]lans to replace the energy, capacity, and reliability services that are currently provided by Boswell Unit 4 are outside the timeframe of the current planning period."[189]

In fact, the stated retirement date is not outside the plan's timeframe; this resource plan goes through 2035, and Minnesota Power claims that its Preferred Plan includes concrete steps to cease coal use at Boswell 4 "in 2035."[190] However, even if Boswell 4's retirement were scheduled for just after the planning period, Minnesota Power repeatedly stresses that it will take ten years or more to complete the kind of large transmission project or large resource addition needed to replace Boswell 4.[191] These years of effort and their associated costs should certainly have been

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[187] *Id*. at 3.
[188] Minnesota Power's Response to CEO IR 80, Minn. Pub. Utils Comm'n, Docket No. E015/RP-21-33 (Dec. 13, 2021).
[189] *Id.*
[190] MP IRP at 3.
[191] *See, e.g*., MP IRP, Appendix P, at 4, 12, 30.

included in this IRP, and their absence is striking. Replacing Boswell 4 is the most difficult resource planning challenge Minnesota Power faces during the period of this IRP, yet its Preferred Plan completely evades it.

Indeed, Figure 17 of Minnesota Power's IRP shows its continued heavy reliance on coal in 2035. The utility currently depends on coal for over 800 MW of capacity, more than half its total capacity.[192] Under its Preferred Plan, Minnesota Power's dependence on coal capacity in 2035 would remain over 400 MW – from the unretired Boswell 4 unit – or close to 30% of its total capacity. Figure 18 of the IRP shows energy from coal actually increasing between 2031 and 2035.[193]

Under these circumstances, Minnesota Power's claim that its Preferred Plan "will result in the Company providing a power supply that is coal-free by 2035" is not reflected in its plan, either through modeling or other necessary planning. Minnesota Power may be *claiming* it will be coal-free by 2035, but it is not *planning* to be coal-free by that year.

B. Minnesota Power Has Failed To Comply With The Commission's Order To Include In This IRP An "Analysis That Thoroughly Evaluates And Includes A Plan For The Early Retirement" Of Boswell 4.

In its order approving NTEC, the Commission explicitly required Minnesota Power to include in this resource plan a "baseload retirement analysis that thoroughly evaluates and includes a plan for the early retirement of Minnesota Power's two remaining coal plants, Boswell 3 and 4, individually and in combination."[194] As discussed above, Minnesota Power's Preferred Plan fails to plan even the on-schedule retirement of Boswell 4 (at the end of 2035, when the unit will be 55

[192] MP IRP at 61.
[193] *Id*. at 62.
[194] AIA Approval, *supra* note 74, at 29.

years old and fully depreciated).[195] But Minnesota Power has also failed to include in its IRP, even among the rejected scenarios, anything that could be called a plan for Boswell's early retirement.

The Commission's order on this point is particularly important given that retiring the nation's coal plants by 2030 is a critical component of the several new studies charting a pathway to limit warming to 1.5°C. Boswell 4 emitted an average of over 3.5 million tons per year of CO_2 during 2018 to 2020,[196] and it is likely to become the state's largest carbon emitter by far after 2030, when Xcel's coal plants are retired.[197] Retiring Boswell 4 would also yield striking human health benefits. The unit is estimated to have caused over $50 million in health impacts in 2021, including causing up to 4.6 premature deaths that year, as CEOs discuss in Part VIII.[198] Every year's delay in retiring Boswell 4 perpetuates these enormous harms.

Minnesota Power indicates that its "Baseload Retirement Study" in Appendix P of its IRP represents compliance with the Commission's order requiring an analysis that thoroughly evaluates and includes a plan for the early retirement of Boswell 3 and 4.[199] However, Appendix P is not a plan for Boswell 4's early retirement; in fact, it reads more like a discussion of why Minnesota Power would rather *not* retire Boswell 4, repeatedly stressing how hard it will be to replace its grid-supporting services and how long it will take.[200] Minnesota Power also, in another IRP appendix, estimates that the transmission upgrades needed to retire Boswell 4 will cost from

[195] Boswell 4 will be fully depreciated by the end of 2035. MP IRP, Appendix P at 2.
[196] PSE Report at Section 3.2.1, Table 1.
[197] Based on data from EPA's Facility Level Information on Greenhouse Gases Tool (FLIGHT), *available at* https://ghgdata.epa.gov/ghgp/main.do?site_preference=normal.
[198] PSE Report at Section 3.2.2, Table 3. These health estimates are based estimated 2021 generation.
[199] MP IRP, Appendix P, at 1.
[200] Minnesota Power states that "in the event of BEC3 and 4 retirements, the evaluations indicate significant transmission investment and/or in-place dispatchable generation will be needed to serve regional reliability needs, and these solutions will likely require ten years or more to implement from the time a retirement decision is made." *Id*. at Appendix P, 12; *see also id.* at 17, 18, 30.

$0.5 to 1.3 billion,[201] a cost range so wide that it illustrates Minnesota Power's failure to thoroughly evaluate the needed upgrades. Moreover, Minnesota Power's IRP does not describe how it would replace Boswell 4's energy and capacity in this upgraded-transmission scenario, or estimate the cost of that replacement energy and capacity.

Minnesota Power does include one scenario in its Swim Lane comparison that purports to retire both Boswell 3 and 4 early, called the Expedited Retirement of BEC 3 and 4 scenario.[202] This scenario does not include the extensive transmission upgrades referenced in Appendix P; rather, it would avoid them by replacing Boswell 4 in 2031[203] with a new 593 MW combined cycle gas plant that lacks carbon capture. However, it is utterly unrealistic for Minnesota Power to assume the availability of this option. Building such a plant is already incompatible with the 1.5°C pathways (see Part I) and will be even more so in the future; indeed, the Biden Administration, consistent with the science and pathway studies, is aiming for a power grid that is carbon-free by 2035. This scenario for retiring Boswell 4, dependent upon an option virtually certain to be unavailable, also falls far short of the thorough evaluation and plan for Boswell's early retirement that the Commission ordered.

C. The Commission Should Order Minnesota Power To Start Planning The Transmission System Reliability Solutions Needed To Allow The Retirement Of Boswell 4 by 2030.

In the reply to CEOs' information request, Minnesota Power also stated, "[g]iven the 2021 IRP analysis supported no immediate action on Boswell Energy Center Unit 4, as outlined in the

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[201] MP IRP, Appendix F, at 65.
[202] MP IRP at 49-50. The validity of the Swim Lane comparison is severely undermined by the fact that the Minnesota Power's Preferred Plan does not include any actual steps to retire Boswell 4, discussed in Part V.A, despite claims that the plan will lead to a coal-free system by 2035.
[203] The 2031 date is set forth in the text of MP IRP, Appendix K, at 15. By contrast, a graphic in the IRP suggests the CC plant would be added in 2029/2030. MP IRP, Figure 14, at 50. Both dates are implausible given the need for deep decarbonization by 2030 with the power sector in the lead.

Baseload Retirement Study and IRP analysis, replacement options and timelines for Boswell Unit 4 will be part of the next IRP."[204] Putting aside the surprising suggestion that a fifteen-year resource plan should only set forth "immediate steps," Minnesota Power is wrong in this claim too. In fact, its Baseload Retirement Study shows that Minnesota is *behind schedule* in taking the concrete steps needed to retire Boswell 4, at least if there is to be any realistic chance to retire it by 2030 in compliance with the 1.5°C pathway studies.

Specifically, in Minnesota Power's study of Boswell's retirement, it projects it "would take approximately ten years to implement improvements to the transmission system to accommodate a BEC 4 retirement."[205] This 10-year estimate is not casually asserted; it is stressed several times throughout the Appendices to the IRP.[206] The utility also stresses that Boswell 3 and 4 provide "essential reliability services" to the region.[207] Thus, rather than justifying Minnesota Power's choice to wait until the next IRP before actually planning Boswell 4's retirement, the utility's own analysis proves the urgency of moving forward responsibly right now to plan the transmission upgrades or other transmission reliability solutions needed to replace Boswell.

Minnesota Power based its estimate of how long construction of such a project would take upon its recent experience building the Great Northern Transmission Line.[208] That project involved years of what Minnesota Power calls "pre-planning" (from 2007 through 2011), followed by several years of additional planning, state and federal review, and design and permitting (2012 through 2016), followed by construction (2017 to mid 2020).

[204] Minnesota Power's Response to CEO IR 80, Minn. Pub. Utils Comm'n, Docket No. E015/RP-21-33 (Dec. 13, 2021).
[205] MP IRP, Appendix P, at 30.
[206] MP IRP, Appendix P at 4, 12, 17, 30; Appendix J at 21, 22.
[207] MP IRP, Appendix P, at 17.
[208] *Id.* at 31.

Given the need to retire all coal plants by no later than 2030 and given how long it could take to build the necessary transmission upgrades to allow Boswell's complete retirement, Minnesota Power certainly cannot wait until its next IRP to begin planning. If the next IRP is submitted in 2024 and approved in 2025 (a quicker schedule than usually applies to IRPs), the utility would only have five years or less to complete what it estimates is a ten-year project in order to keep a 2030 retirement as an option. By waiting until its next IRP, Minnesota Power would effectively be making it impossible to retire Boswell 4 in a well-planned way by 2030, at least if what Minnesota Power says regarding how long these upgrades will take proves to be true.

The Commission should therefore order Minnesota Power to begin planning the necessary transmission system reliability solutions now. The planning process should proceed at the pace and to the extent required to keep viable the option of retiring Boswell entirely by 2030. The Great Northern Transmission Line experience illustrates that there are years of planning and permitting work needed before construction commences. Given the reluctance Minnesota Power has shown to plan for Boswell's retirement, the Commission should also require Minnesota Power to file annual updates of its planning progress.

The process of seriously planning the transmission upgrades and other transmission system reliability solutions may reveal that Minnesota Power has overestimated the cost and extent of those upgrades. There is reason to expect that alternatives -- like synchronous condensers, operational adjustments, or contractual arrangements with Manitoba Hydro – could greatly reduce the cost of ensuring reliability upon Boswell 4's retirement. As the Telos Report explains, Minnesota Power's Beyond Boswell study assumes, without explanation, a huge power flow from Minnesota to Manitoba during the winter peak, and Minnesota Power requested that MISO make the same assumption in its Y2 study.[209] However, historically the flow of power during the winter peak is in the opposite direction, from Manitoba to Minnesota, as MISO assumes in its MTEP20 Winter Peak case.[210] As the Telos analysis shows, this single assumption of reversing the winter peak power flow significantly increases the projected reliability problems associated with retiring Boswell 4, and it may well have contributed to a substantial overestimate of the cost and difficulty of building the transmission upgrades needed to prepare for that retirement.[211] Minnesota Power's cost estimate may also be overstated because the utility has not studied promising cost-reducing options identified in the Telos Report, including converting the Boswell units to synchronous condensers and siting storage at critical locations.[212]

Finally, MISO has already included in its March 29, 2022 Long Range Transmission Planning (LRTP) Tranche 1 Portfolio a new power line identified as "Iron Range – Benton – Cassie's Crossing."[213] If built, this proposed line (estimated to cost $853 million)[214] would, according to the Telos Report, provide similar reinforcement to the transmission system as a line proposed by Minnesota Power to enable the retirement of Boswell 4.[215] MISO's Iron Range – Benton – Cassie's Crossing line could therefore greatly reduce the transmission upgrades that Minnesota Power alone would be responsible for.[216]

If Minnesota Power is right, and the needed transmission upgrades are as extensive and costly as it estimates in this IRP, it is critical to move ahead with planning them immediately.

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209 Telos at Section 3.3.4.
210 *Id.*
211 *Id.* at Section 7.4.
212 *Id.* at Section 5.4.
213 *LRTP Tranche 1 Portfolio Detailed Business Case,* MISO, LRTP Workshop, 42 (Mar. 29, 2022) *available at* https://cdn.misoenergy.org/20220329%20LRTP%20Workshop%20Item%2002%20Detailed%20Business%20Case623671.pdf.
214 *Id.* at 13.
215 *Telos* at Section 5.4.
216 *Id.*

However, CEOs believe the planning process – which should begin now and not in the next IRP – is likely to identify more cost-effective options.

VI. THE COMMISSION SHOULD RECOGNIZE THAT MINNESOTA'S CARBON REGULATORY COST ESTIMATES DO NOT REFLECT THE FULL REGULATORY RISK AND SHOULD COMMENCE A PROCEEDING TO UPDATE THEM

The current estimate of the likely range of costs of future carbon regulation, adopted pursuant to Minn. Stat. § 216H.06, is outdated.[217] It does not reflect the material changes in climate science and policy or the far more aggressive decarbonization targets the power sector now faces, as discussed in Part I.A and I.B. The Commission should recognize the presence of this unaccounted-for regulatory risk in assessing this IRP. It should also commence a proceeding to update its carbon regulatory cost estimates to reflect today's climate policy landscape, as required by section 216H.06.

The Commission's most recently adopted CO_2 regulatory cost estimates still reflect the assumption that the only carbon regulatory cost faced by the power sector will be the requirement to pay a relatively modest cost per ton of carbon emitted under a cap-and-trade system aiming for economy-wide carbon cuts of around 80% over four decades.[218] For years that was a reasonable assumption, reflecting as it did the emission reduction schedule and regulatory mechanism then at the center of the state and federal debate. Today, however, both the reduction schedule and the expected regulatory mechanisms have changed.

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[217] Minn. Pub. Utils. Comm'n, *In the Matter of Establishing an Updated 2020 Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation under Minn. Stat. § 216H.06*, Order Establishing 2020 and 2021 Estimate of Future Carbon Dioxide Regulation Costs, Docket No. E-999/DI-19-406 (Sep. 30, 2020).

[218] For example, the Waxman-Markey bill, which passed the U.S. House in 2009, sought an 83% reduction in economy-wide carbon emissions by 2050. *Waxman-Markey Short Summary*, Center for Climate and Energy Solutions (June, 2009) *available at* https://www.c2es.org/document/waxman-markey-short-summary/.

First, the power sector now faces the prospect of having to decarbonize 100% in 13 years rather than 80% in 40 years – a far steeper emission reduction trajectory. The goal of a carbon-free power sector by 2035 has been adopted by the Biden Administration.[219] At the state level, Minnesota's Governor Walz has announced his support for a carbon-free power sector by 2040, a goal nearly as ambitious as the Biden Administration's.[220] These more ambitious goals are part of a larger effort to limit warming to no more than the globally-embraced target of 1.5°C. The pathway studies discussed in Part I.B indicate that to achieve that target, the nation will likely need policies that will close existing coal plants by 2030 and prevent the building of new gas plants lacking carbon capture. The current carbon regulatory cost estimates do not reflect the costs of such policies, even at their upper range.

Second, cap-and-trade is no longer expected to be the sole or even primary regulatory mechanism to achieve the power sector's decarbonization.[221] Decarbonization of the power grid is now more widely expected to be driven by some mix of carrots and sticks. The carrots include more aggressive support of critical decarbonization technologies like renewable energy, energy storage, and related transmission, including the unprecedented investment in last year's infrastructure bill and over $500 billion in tax credits and other energy spending that appears to

[219] White House Fact Sheet, *supra* note 18.
[220] Office of Governor Tim Walz and Lt. Governor Peggy Flanagan, *Governor Walz, Lt. Governor Flanagan, House and Senate DFL Energy Leads Announce Plan to Achieve 100 Percent Clean Energy in Minnesota by 2040* (Jan. 21, 2021) *available at* https://mn.gov/governor/news/?id=1055-463873.
[221] We note that if a carbon price alone were to drive decarbonization, the power sector could expect prices far higher than the current estimate of $5-25/ton; a recent analysis by Wood Mackenzie finds it would take carbon prices of $160/ton by 2030 to achieve greenhouse gas reductions in line with a 1.5 ° target. Wood-Mackenzie, *Significant Increase in Carbon Pricing is Key in 1.5-degree World*, (Mar. 4, 2021), *available at* https://www.woodmac.com/press-releases/significant-increase-in-carbon-pricing-is-key-in-1.5-degree-world/#:~:text=Wood%20Mackenzie's%20latest%20scenario%20report,to%20within%201.5%20degrees%20Celsius.

have sufficient support in Congress this year.[222] The sticks could someday include a Clean Energy Standard, but given that the standard that passed the House last year is now blocked in the Senate, the Biden Administration plans to adopt aggressive EPA rules to ensure the rapid reduction of power sector emissions to meet the 2035 deadline.[223]

No reasonable estimate of the range of future carbon regulatory costs faced by electricity generation can afford to ignore the reduction targets and policy steps currently at the center of the climate policy debate. Political delays in these policy efforts just make it likely that even steeper emission cuts will be required by the power sector in a few years. Climate change is not slowing, and the need is growing for accelerated decarbonization of the power grid in this decade and the next. Minnesota utilities cannot prudently make long-term investments if they fail to acknowledge the possibility that society, mobilizing in an unprecedented way against an unprecedented global danger, will actually do what is scientifically necessary, economically and technologically possible, and politically supported by the nation's and state's leadership.

We also note that the current approach to future carbon regulatory costs can lead to highly irrational outcomes when combined with the Commission's estimated environmental externality costs.[224] Once the carbon regulatory costs are presumed to begin in 2025, utilities are allowed to assume that the environmental costs of carbon emissions disappear. The Commission's current estimate of carbon regulatory costs for 2025 ($5-25/ton) is much lower than its estimate of carbon environmental costs for 2024 ($9.87-46.06/ton). Thus, the portion of the total social cost associated

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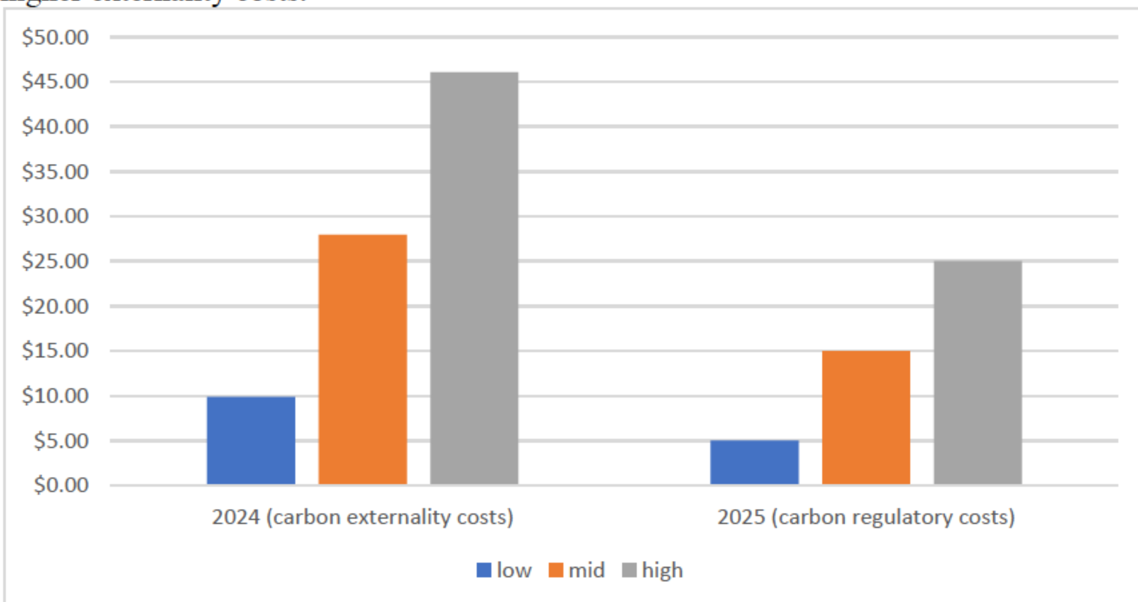
[222] Coral Davenport and Lisa Friedman, *"Build Back Better" Hit a Wall, but Climate Action Could Move Forward,* New York Times (Jan. 20, 2022), *available at* https://www.nytimes.com/2022/01/20/climate/build-back-better-climate-change.html

[223] Coral Davenport, *Biden Crafts a Climate Plan B: Tax Credits, Regulation and State Action,* New York Times (Oct. 22, 2021), *available at* https://www.nytimes.com/2021/10/22/climate/biden-climate-plan.html.

[224] Minn. Pub. Utils. Comm'n, *In the Matter of the Further Investigation into Environmental and Socioeconomic Costs Under Minnesota Statutes Section 216B.2422, Subdivision 3,* Order Updating Environmental Cost Values, Docket No. E-999/CI-14-643 (Jan. 3, 2018).

with carbon emissions drops nearly in half in 2025 (see Figure 3), suggesting those emissions are suddenly much less of a problem when in fact both the climate crisis and carbon regulatory risk will surely be intensifying.

Figure 3. Carbon externality costs versus carbon regulatory costs. The Commission's estimated carbon regulatory costs, assumed to begin in 2025, substitute for considerably higher externality costs.[225]



The true costs of carbon emissions – both to the utility and society – also get obscured in another way, as illustrated by the strange results of Minnesota Power's EnCompass modeling. Minnesota Power's IRP compares its Preferred Plan with Swim Lanes where one or both Boswell units are retired earlier. It repeats that comparison under each of the five different environmental futures the Commission requires, assuming higher and lower regulatory and environmental costs in different combinations.[226] The Preferred Plan comes out cheaper than earlier retirement of the Boswell units under most of the 38 sensitivities examined when assuming mid-level regulatory and environmental costs (the results Minnesota Power featured in the IRP[227]) and when assuming

[225] *Id.* at 9-10.
[226] *Id.* at 9.
[227] MP IRP at 57.

high carbon costs and high environmental costs (the results submitted with the IRP as Appendix K[228]).

Counterintuitively, though, under the other three environmental futures, which assume no or low carbon costs, Minnesota Power's modeling finds that it is actually cheaper to retire one or both Boswell units earlier (results submitted after the IRP as Supplemental Appendix K[229]). Indeed, assuming a future with no carbon regulatory costs, early retirement of both Boswell units has a lower cost than the Preferred Plan under virtually all 38 sensitivities.[230] In other words, instead of high carbon regulatory costs driving the earlier retirement of Boswell 3 and 4, Minnesota Power's modeling suggests that high carbon regulatory costs are a reason to delay their retirement. Minnesota Power dismissed the three environmental futures that favored earlier retirement of Boswell as reflecting an "environmental future design shortcoming."[231] However the same design shortcoming applies to the two scenarios that favor the Preferred Plan.

Together these upside-down scenarios illustrate that the Commission cannot assume that Minnesota Power's IRP reflects actual carbon regulatory risk merely because its modeling incorporates the Commission's estimated carbon costs. They also illustrate another reason why the Commission should update its regulatory cost estimates and its rules for how they are applied to ensure they yield analyses that are useful to long-term resource planning.

[228] MP IRP, Appendix K at 17.
[229] MP IRP, Supplemental Appendix K, at 26-28.
[230] *Id.*
[231] *Id.* at 24.

VII. A MINNESOTA POWER RESOURCE PORTFOLIO THAT INCLUDES MORE DISTRIBUTED SOLAR PRESENTS AN OPPORTUNITY TO BE CLEANER AND MORE EQUITABLE, CREATE JOBS FOR MINNESOTANS, AND PROVIDE COST-EFFECTIVE SOLAR TO THE SYSTEM

Multiple recent studies have shown that investing in distributed solar generation can lower system costs, deliver cleaner energy, and create more local jobs than portfolios that only focus on utility-scale resources.

For example, a recent study by Vibrant Clean Energy, LLC, "Why Local Solar For All Costs Less: A New Roadmap for the Lowest Cost Grid: Technical Report," illustrates how traditional capacity expansion planning models fail to capture the reliability benefits of distributed generation.[232] In the study, VCE used the *Weather-Informed energy Systems: for design, operations and markets planning* (WIS:dom®- P) optimization software tool, which is a combined capacity expansion and production cost model.[233] Traditional modeling tools do not integrate and optimize the benefits of locally-sited solar and storage. One of the key differences between WIS:dom and other modeling tools is its ability to optimize the addition of distributed solar and storage as resources, instead of using a pre-determined buildout rate as a load modifier (as Minnesota Power has done in its IRP modeling).[234]

In its study, VCE evaluated whether distributed energy resources (distributed solar PV, energy efficiency, demand-side management, demand response, and distributed storage, or "DER") can lower costs across the US electricity system compared to alternatives, while maintaining resource adequacy, reliability and resilience. The study found that customers could

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[232] *Why Local Solar for All Costs Less: A New Roadmap for the Lowest Cost Grid,* Vibrant Clean Energy, LLC, on behalf of Local Solar for All, Vote Solar, and Coalition for Community Solar Access, (Dec. 1, 2020) *available at* https://www.vibrantcleanenergy.com/wp-content/uploads/2020/12/WhyDERs_TR_Final.pdf.
[233] *Id.* at 1.
[234] *Id.* at 1-3.

save a cumulative $473 billion by employing a clean energy standard that reduces emission by 95% from 1990 levels by 2050, while creating 2 million more jobs nationally.[235] (On a population basis, this translates into 33,800 additional jobs in Minnesota.) This cleanest, lowest-cost grid requires 223 GW more local solar nationwide.[236] The report found that traditional utility planning based on construction of utility scale generation fails to take into account the many benefits of a more distributed resource system, leading to an over-reliance on overbuilding peaking plants. Adding an optimal amount of distributed resources (by considering these benefits) allows the transmission system to be better utilized, and reduces the amount of peaking resources required. VCE's optimization shows that dramatically more distributed generation is beneficial than traditional models and utility planning account for.

Minnesota Power's proposed plan understates the role that community solar and distributed solar generation can and should play in its future. The Company modeled DG as a modifier to its load forecast. In doing so, Minnesota Power overlooks the role it can play in incentivizing its customers to leverage their own capital to the benefit of the system. As Sierra Club and the Distributed Solar Parties ("DSPs") showed in the Xcel IRP, the utility can encourage incremental distributed generation additions at a lower cost than utility-scale solar.[237] For IRP modeling purposes, the total resource cost is the cost to the utility of offering an incentive, such as an upfront rebate. In the Xcel IRP, Sierra Club and the DSPs modeled bundles of DG at each incentive level,

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235 *Id.*
236 *Id.*
237 Minn. Pub. Utils. Comm'n, Sierra Club's Initial Comments, *In the Matter of Xcel Energy's 2020-2034 Upper Midwest Resource Plan*, Docket No. E002/RP-19-368, 38-40 (Feb. 11, 2021); Minn. Pub. Utils. Comm'n, Joint Comments of Vote Solar, Institute for Local Self Reliance, the Environmental Law and Policy Center, and Cooperative Energy Futures, *In the Matter of Xcel Energy's 2020-2034 Upper Midwest Resource Plan*, Docket No. E002/RP-19-368 (Feb. 11, 2021).

similar to how Minnesota utilities model energy efficiency, and found that adding over 1,800 MW of distribution-connected solar would significantly decrease the overall plan costs.

In response to advocacy on the part of Minnesota Interfaith Power & Light and other local partners, Minnesota Power now offers a low-income solar grant program. This program should be expanded to provide greater opportunities for low-income MP customers to access the benefits of distributed solar. Moreover, as a significant percentage of low-income residents in Duluth are renters, not homeowners, Minnesota Power has an opportunity to expand low-income community solar projects to further increase equitable access to distributed solar.

A plan that includes both robust investment in utility scale renewables as well as strong deployment of distributed and low-income-focused community solar can deliver more in terms of job creation and community-located investment and is a key tool to a more equitable energy delivery system. Because of the benefits that distributed solar generation can offer to Minnesota Power's customers, Minnesota Power should work with stakeholders to develop a modeling construct that enables the utility to model solar-powered generators connected to the company's distribution grid as a resource, take steps to better align distribution and resource planning, and consider local community generation goals for distributed generation in its next IRP.

VIII. RETIRING BOSWELL AND HIBBARD EARLY AND NOT BUILDING NTEC WOULD GREATLY REDUCE HUMAN HEALTH IMPACTS, ESPECIALLY IMPACTS ON OVERBURDENED COMMUNITIES

A. The Commission Should Take Into Account Health And Equity When Examining Minnesota Power's Resource Plan.

The Commission evaluates resource plans, in part, for their ability to "minimize adverse socioeconomic effects and adverse effects upon the environment,"[238] and, ultimately, the

[238] Minn. R. 7843.0500, subp. 3(C).

Commission is tasked with choosing a resource plan in the public interest.[239] As the State of Minnesota moves to decarbonize our energy sector, utility resource planning has major implications for public heath, environmental justice, economic development, worker and community energy transition impacts, and socio-economic disparities. In this docket, the Commission is considering the future of Minnesota Power's existing fleet and the changes that need to be made to meet future demand. These decisions should not be made without carefully considering the public health impacts of Minnesota Power's existing resources. And, examining public health and equity impacts is especially consequential in dockets like this one where the alternate generation portfolios presented by CEOs show only very small differences in direct cost.[240]

A broad range of stakeholders, as well as the Commission, have recognized the connections between resource planning and equity. In the recent Xcel IRP, many intervenors raised health and equity concerns. In that IRP, Clean Grid Alliance, Fresh Energy, Minnesota Center for Environmental Advocacy, Union of Concerned Scientists,[241] Sierra Club,[242] Energy Efficiency for All Partners,[243] the City of Minneapolis,[244] St. Paul 350,[245] among others, all implored the Commission to center equity when making a resource planning decision. The Commission's

[239] Minn. Stat. § 216B.2422, subd. 2(a).
[240] *See* Part III.
[241] Minn. Pub. Utils. Comm'n, CEOs' Initial Comments, *In the Matter of Xcel Energy's 2020-2034 Upper Midwest Resource Plan*, Docket No. E002/RP-19-368, 43 (Feb. 11, 2021).
[242] Minn. Pub. Utils. Comm'n, Sierra Club's Initial Comments, *In the Matter of Xcel Energy's 2020-2034 Upper Midwest Resource Plan*, Docket No. E002/RP-19-368, 97 (Feb. 11, 2021).
[243] Minn. Pub. Utils. Comm'n, Comments of Fresh Energy, Community Stabilization Project, Green & Healthy Homes Initiative, Inquilinxs Unidxs Por Justicia, Minnesota Housing Partnership, National Housing Trust, and Natural Resources Defense Council ("EEFA Partners"), *In the Matter of Xcel Energy's 2020-2034 Upper Midwest Resource Plan*, Docket No. E002/RP-19-368, 2-5 (Feb. 11, 2021).
[244] Minn. Pub. Utils. Comm'n, Comments of the City of Minneapolis, *In the Matter of Xcel Energy's 2020-2034 Upper Midwest Resource Plan*, Docket No. E002/RP-19-368, 5 (Feb. 11, 2021).
[245] Minn. Pub. Utils. Comm'n, SP350 Initial Comments, *In the Matter of Xcel Energy's 2020-2034 Upper Midwest Resource Plan*, Docket No. E002/RP-19-368, 8 (Feb. 11, 2021).

decision in that docket requires Xcel to conduct community outreach and go through a stakeholder process to achieve various equity goals. Those equity measures include, "equitable delivery of electricity services and programs" and designing incentives "that ensure that communities of low income, Black, indigenous, and People of Color that have disproportionately borne costs of unjust and inequitable energy decisions have equitable access to programs promoting distributed generation."[246]

CEOs ask the Commission to examine disparate health impacts in this docket because historical decisions around power plant siting have systematically exposed BIPOC communities across the country to higher levels of harmful air pollution,[247] among other hazards. Minnesota is no exception; for example, the Minnesota Pollution Control Agency has recognized that "discriminatory housing policies, the placement of freeways in Black neighborhoods, and zoning and permitting decisions" resulted in BIPOC communities experiencing higher pollution.[248] One salient example for this docket is the Boswell Energy Center's close proximity to the Leech Lake Band of Ojibwe land. Boswell was built abutting the border in the 1950s during the United States' "Voluntary Relocation Program," a program designed to "assimilate American Indians" by forcing them off of reservation lands and into the cities.[249] Our State has recognized that "[d]isparities in Minnesota, including those based on race, geography, and economic status, keep our entire state

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[246] Minn. Pub. Utils. Comm'n, Order Approving Plan with Modifications and Establishing Requirements for Future Filings, *In the Matter of Xcel Energy's 2020-2034 Upper Midwest Resource Plan*, Docket No. E002/RP-19-368, para. 25 (Apr. 15, 2022).

[247] Haley M. Lane, et al., *Historical Redlining Is Associated with Present-Day Air Pollution Disparities in U.S. Cities,* Environmental Science and Technology Letters (2022), *available at* https://pubs.acs.org/doi/pdf/10.1021/acs.estlett.1c01012.

[248] *The air we breathe: The state of Minnesota's air quality in 2021*, Minn. Poll. Control Agency, 7 (Jan. 1, 2021) *available at* https://www.pca.state.mn.us/sites/default/files/lraq-2sy21.pdf.

[249] *American Indian Urban Relocation Program,* U.S. Nat'l Archives, *available at* https://www.archives.gov/education/lessons/indian-relocation.html.

from reaching its full potential."[250] As one step towards addressing these disparities, CEOs ask the Commission to consider public health and equity in this IRP.

B. Incorporating Health And Equity Metrics Report Methodology

CEOs commissioned a report from Physicians, Scientists, and Engineers for Healthy Energy ("PSE") to include as part of CEOs' filing. "PSE is a multidisciplinary, nonprofit research institute dedicated to supplying evidence-based scientific and technical information on the public health, environmental, and climate dimensions of energy production and use."[251] The purpose of this report is to evaluate the public health and energy burden impacts of Minnesota Power's Preferred Plan.

CEOs have included this report from PSE to provide one example of how equity issues can be included in a direct and quantitative manner in resource planning proceedings. PSE focuses the report on three primary areas: excess mortality caused by coal and biomass plant emissions, lifecycle greenhouse gas impacts of new gas plants like NTEC, and strategies to reduce energy burden and improve equity of clean energy access. CEOs recognize that this analysis does not cover every equity issue implicated by Minnesota Power's resource plan; rather, PSE focuses on three issues emphasized by CEOs.

First, the PSE report evaluates public health impacts of coal use and the potential benefits from retiring these facilities early. Although coal and biomass plants produce a variety of emissions, the PSE report focuses on $PM_{2.5}$ for two reasons: $PM_{2.5}$ typically represents the majority of adverse impacts from coal plant emissions, and there are established and widely accepted ways

[250] Exec. Order 19-01, Establishing the One Minnesota Council on Diversity, Inclusion, and Equity, State of Minnesota, Exec. Dep't. (Jan. 9, 2019) *available at* https://mn.gov/governor/assets/2019_01_09_EO-19-01_%28FINAL%29_tcm1055-364605.pdf.
[251] PSE Report, Executive Summary.

to model $PM_{2.5}$. However, this health impact modeling likely underestimates health impacts caused by pollutants that are not modeled.[252]

To establish a baseline for coal and biomass emissions, PSE used emissions data from historic operations. Then, PSE modeled the anticipated health impacts from Minnesota Power's planned usage of the coal and biomass plants for 2021-2035. These health impacts include nonfatal heart attacks, respiratory-related hospital admissions, upper respiratory symptoms, and mortality.[253] The PSE Report estimated mortality resulting from operation of the plant and how those deaths are concentrated geographically around the plants.[254] In addition to health impacts from emissions, the PSE report also explores toxicity and environmental impacts from coal ash disposal, as well as coal plant water usage.[255]

Importantly, PSE examined *which* communities are experiencing these health impacts. The report maps the geographic distribution of each power plant's emissions and presents the overall demographic and racial disparities of the health impacts resulting from these coal and biomass resources.[256] PSE also takes a deeper look at the communities in closest proximity to each plant, which are generally the most-impacted populations. They use a Demographic Index composed of six key factors to evaluate the socio-economic characteristics and relative vulnerability to air pollution of plant host communities compared to the general population.[257]

Second, the PSE report highlights the underestimated methane emissions for gas plants like NTEC. Due to significant leakage throughout the entire gas system, the climate impacts of gas plants like NTEC are much higher than simply the CO_2e [or greenhouse gas] emissions produced

[252] *Id.* at Section 2.2.
[253] *Id.* at Section 3.2.2.
[254] *Id.* at Section 3.2.4.
[255] *Id.* at Sections 3.2.5 and 3.2.6.
[256] *Id.* at Sections 2.1 and 2.2.
[257] *Id.* at Section 2.1.

directly at the power plant. The report uses recent scientific literature to estimate the actual global warming contributions of NTEC considering upstream emissions.[258]

Third, the PSE report evaluated the energy access and equity issues facing Minnesota Power's customers. Because granular data is not available for residential energy consumption, PSE started by estimating household energy consumption in each census tract using a linear regression model that approximates energy consumption by fuel type and how the energy is being used. Then, PSE used census tract-level energy consumption to estimate how much households are spending on energy. Finally, PSE compared the energy expenditures in each census tract with the census tract's median household income in order to arrive at the "cost burden."[259]

C. Report Findings.

1. Minnesota Power's coal and biomass facilities have significant public health consequences.

PSE's public health analysis found that the coal and biomass power plants currently in Minnesota Power's portfolio have significant local and regional health impacts. Collectively, emissions from Boswell, Hibbard, and Minnesota Power's purchases from Milton R. Young were responsible for 16 excess deaths and $177 million in public health costs in 2021.[260] This cost figure represents an estimate of the monetary value of additional hospital visits, healthcare requirements, missed work and school, etc., that result from the health impacts of fine participate pollution ($PM_{2.5}$), which include exacerbated asthma, heart attacks, irregular heartbeat, premature birth, and premature death.

PSE's modeling indicates that, if these three plants run as described in Minnesota Power's Preferred Plan between now and 2035, they will cause an additional 100 premature deaths (on

[258] *Id.* at Section 3.4.
[259] *Id.* at Section 2.4.
[260] *Id.* at Section 3.2.2.

average, 6-7 deaths per year) and over $1 billion in public health costs.[261] It is worth noting again that these mortality and public health cost estimates are conservative. They are based exclusively on the impacts of $PM_{2.5}$ and do not include additional impacts from VOCs, NO_X, SO_2, or ozone. Additionally, these figures only include the impacts from Minnesota Power's purchases from Young which are set to end after 2025, while the plant is likely to continue operating well past that date.

PSE evaluated the public health benefits of earlier retirement dates for the two Boswell units. It found that retiring Unit 3 five years early (at the end of 2024 instead of 2029) would save 3-4 lives and $39 million in health costs, while retiring Unit 4 after 2029 instead of running it through 2035 would save 14-15 lives and $164 million in health costs.[262] PSE also found that earlier retirements would have significant benefits for reducing coal ash waste stored on the Boswell site. Coal ash at Boswell contains several highly toxic substances that can cause adverse human and wildlife health impacts and poses a "significant hazard" to nearby communities if Boswell's coal ash ponds were to fail.[263]

PSE also evaluated the public health impacts of the Milton R. Young coal-fired power plant and found that Young has large public health costs for Minnesotans. In fact, PSE found that "its cumulative health impacts in Minnesota are actually slightly higher than in North Dakota itself."[264] PSE's modeling shows that the electricity MP has committed to purchase from Young is expected to cause 3-4 excess deaths per year and $110 million in health costs through 2025, when the contract expires. Unless the contract expiration coincides with a reduction to plant output, however, these adverse health impacts will continue.

[261] *Id.* at Section 3.2.3.
[262] *Id.* at Section 3.2.3.
[263] *Id.* at Section 3.2.5.
[264] *Id.* at Section 3.2.4.

The public health impacts of the Hibbard biomass and coal plant are perhaps the most stark and actionable finding in this analysis. While the plant's future operations are hard to predict due to recent changes at the associated paper mill, the historical emissions and impacts on the surrounding community are enormous, especially considering the plant's size. PSE's evaluation of 2021 data shows that Hibbard had greater adverse health impacts than any of the other plants: 6.7 excess deaths, versus 6.2 from Boswell, and $70 million in estimated public costs, versus $67.7 million from Boswell.[265] Hibbard has a nameplate capacity of 47MW, roughly 5% the size of Boswell – and yet its adverse health impacts exceed those of a coal plant 20 times its size. These factors indicate that the public interest will be best served by shutting Hibbard down as soon as possible.

Table 6. Health Impacts of Minnesota Power's Coal and Biomass Power Plants

	Hibbard	**Boswell**	**Young**
Plant Size	47MW	932MW	439MW
Excess Deaths - 2021	6.4 deaths	6.2 deaths	3.5 deaths
Public Health Costs - 2021	$70 million	$67.7 million	$39 million
Excess Deaths – projected through 2035	Unknown	47.5 deaths	10 deaths
Public Health Costs - projected through 2035	Unknown	$534 million	$110 million

2. The health costs of these plants fall most heavily on lower-income communities, communities of color, and Native populations.

Communities located nearest to and downwind of these plants face the highest per-capita health consequences. PSE's evaluation of the socio-economic and geographic distribution of health impacts from the plants found that health costs are disproportionately impacting

[265] *Id.* at Section 3.3.

communities with high socio-economic burdens that make residents more vulnerable to the respiratory and cardiac impacts from $PM_{2.5}$.[266]

PSE's modeling of the geographic distribution of Boswell's health consequences shows that the plant impacts a huge swath of the country, spanning from northeastern Minnesota to the mid-Atlantic. However, per capita impacts are highest in Minnesota communities surrounding and east of the plant.[267] The community living closest to Boswell is significantly lower-income and more vulnerable to pollution impacts than the Minnesota population at large: PSE found that the population within one mile of Boswell ranks at the 81st percentile for low-income populations and ranks at the 71st percentile on PSE's Demographic Index, which combines several demographic factors to provide a composite risk score.[268] The racial distribution of these health costs is quite uneven: Native populations face per-capita health costs from Boswell that are nearly three times higher than the overall population.[269]

Due to the Young plant's remote location, PSE did not evaluate the *immediate* community's demographics, but its overall per-capita health impacts are quite unevenly distributed: Native populations face public health costs 2.5 times greater than the overall population impacted by emissions from the Young plant.[270]

Importantly, Hibbard is located in an urban area with a significant population nearby – 30,000 people live within a three-mile radius – and near lower-income communities and populations more vulnerable to health impacts of air pollution. PSE found that the population within one mile of the plant is lower income than 89% of census tracts in Minnesota, and more

[266] *Id.* at Section 4.
[267] *Id.* at Section 3.2.4.
[268] *Id.* at Section 3.1.
[269] *Id.* at Section 3.2.4.
[270] *Id.*

vulnerable (per PSE's Demographic Index) than 78% of the state. Additionally, Hibbard's pollution disproportionately impacts Native populations, who face health costs from Hibbard three times higher than the overall impacted population.[271]

In fact, PSE found that "for every plant analyzed, the health impacts per capita were highest for Native populations, and larger by a factor of two to three as compared to the population at large."[272] This is likely due to the location of many of these plants close to and upwind of Tribe lands and populations. Hibbard is located just east of the Fond du Lac reservation and upwind of Grant Portage, while Young is located upwind of all tribal lands in Minnesota. The Boswell facility is located directly adjacent to the Leech Lake Band of Ojibwe reservation boundary and is upwind from the Fond du Lac, Milles Lacs, Bois Forte, and Grand Portage Reservations.

The disproportionate impacts that pollution from Hibbard and Boswell have on lower-income and Tribal communities in Minnesota is a critical factor to consider in decisions about these facilities' futures. CEOs have discussed the results of this report with representatives of several of the Tribes noted above. We hope to have ongoing conversations about how to best utilize this information and how to improve public health and equity analyses for future regulatory proceedings. Input from Tribes, native residents, and others directly impacted by the health costs of these plants will be quite valuable to this proceeding.

CEOs urge the Commission to consider the magnitude of these public health impacts when making decisions about future plant operations and Minnesota Power's generation portfolio. In the case of Hibbard, the public interest is clear – not only is this plant exacting dramatic health costs on nearby communities, but CEOs' modeling shows that continued operation of Hibbard is unnecessary, and an immediate 2023 retirement is cost effective.

[271] *Id.* at Section 3.1.
[272] *Id.* at Section 3.2.4.

3. Accounting for upstream methane emissions and facility N_2O emissions doubles NTEC's expected climate impacts.

PSE's evaluation of NTEC focused on providing a comprehensive assessment of the plant's likely climate impacts, specifically by considering the greenhouse gas impacts of upstream methane emissions and the facility's emissions of nitrous oxide ("N_2O"), another extremely potent greenhouse gas. Scientists and policy makers, including the Minnesota Legislature[273] and this Commission,[274] are recognizing the importance of considering upstream methane emissions when evaluating the climate impacts of fossil gas infrastructure. A recent meta-analysis of methane leakage in the U.S. found that methane leaks at a rate of 2.9 % of fossil gas delivered to end-users, and as a result the radiative forcing (global warming impact) of fossil gas over a 20-year horizon is 92% higher than its direct CO_2 emissions from combustion.[275]

The scale of these typically unaccounted-for greenhouse gas impacts is dramatic. In fact, the climate impacts of NTEC more than double when considering upstream methane emissions and facility N_2O emissions. While the most recent air permit for NTEC suggests that the facility will produce 2.24 million tons of CO_2 per year,[276] PSE's analysis found that the actual greenhouse gas impact of the plant will be 4.8 million tons CO_2e annually (when considering a 20-year horizon for methane).[277] MP's share of these emissions, assuming 20% ownership, would be 960,000 tons CO_2e, rather than 448,000 tons CO_2 per year.

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[273] *See* Minn. Stat. § 216B.2427, subd. 2(a)(3); Minn. Stat. § 216B.241, subd. 2(k).
[274] Minn. Pub. Utils. Comm'n, *In the Matter of a Commission Investigation to Identify and Develop Performance Metrics and, Potentially, Incentives for Xcel Energy's Electric Utility Operations*, Order Accepting Report and Setting Additional Requirements, Docket No. E-002/CI-17-401, Order 6-7 (Feb. 9, 2022).
[275] Ramón A. Alvarez, et al., *Assessment of Methane Emissions from the US Oil and Gas Supply Chain. Supplementary Material*, Science, 186-188 (June 21, 2018) *available at* https://www.ncbi.nlm.nih.gov/pmc/articles/PMC6223263/.
[276] Wisc. Dep't. Nat. Resources, Nemadji Trail Energy Center, FID No. 816127840 / Permits 18-MMC-168 and 21-MMC-11 Air Pollution Control Construction Permit Application, Section 1.2 (Dec. 10, 2021).
[277] PSE Report at Section 3.4.

PSE did not model potential PM or NO_x emissions for this yet-to-be-developed plant, but notes that Syl Laskin, MP's fossil gas peaker plant, has a higher rate of NO_x emissions per MWh than Boswell.[278] When meteorological conditions are poor, such as during peak summer days, fossil gas plants can significantly contribute to poor air quality and acute health impacts as "high NO_x emissions may contribute to increased ozone or secondary $PM_{2.5}$ formation."[279]

The Commission should also consider the demographics of the community nearest NTEC, which will be most impacted by the respiratory effects of ozone, secondary $PM_{2.5}$ and related emissions if NTEC is built. The plant is proposed to be located in a population center with 15,000 people living within a three-mile radius of the NTEC site. This population ranks in the 74th percentile for low-income population in Wisconsin and 66th percentile on PSE's demographic index.[280] The proposed NTEC site is also quite close to the Fond du Lac reservation. Given these demographic factors, emissions from NTEC will have public health consequences for a nearby community that is significantly lower-income and more vulnerable to the health consequences of pollution than the state population at large.

4. Minnesota Power should invest more in low-income residential efficiency projects and community solar projects that prioritize access for under-resourced customers to reduce electricity costs and disparities in energy burden.

Assessments of population characteristics in utility service areas can reveal important insights with respect to energy access and equity. The information can in turn lead to potential changes in resource portfolios or be used in other proceedings dealing with how programs such as energy efficiency or distributed solar are structured and applied. As a first step, PSE provides a methodology for calculating average household energy cost burdens for each census tract in utility

[278] *Id.*
[279] *Id.*
[280] *Id.* at Section 3.1.

service areas.[281] Energy cost burden—the percentage of household income used to pay energy bills—is typically considered high if over 6%.[282] PSE found notably high energy burdens in rural areas of Minnesota Power's service territory and particularly in parts of Duluth.[283]

PSE next estimated that the low-income population in Minnesota Power's service area is about 30% of the total population and developed a spatial distribution of low-income households by census tract.[284] PSE noted the especially high concentration of low-income households in the downtown Duluth area. Examining Minnesota Power's energy efficiency investments and projected residential efficiency savings, PSE found that the company's efficiency investments in low-income communities have historically averaged 20% of total efficiency investments, producing projected residential savings in low-income households of only 13% of total savings in the near-term (2021–2023) and only 11% in the longer-term (2024-2029).[285]

These proportions are inequitable given that the fraction of low-income population in Minnesota Power's service area is closer to 30%. Accordingly, PSE recommends that Minnesota Power's investments in low-income residential efficiency should be tripled as a fraction of the total levels of efficiency investment currently planned, while also ensuring that at least one-third of projected energy savings are attained in low-income communities.[286]

Fresh Energy made a similar recommendation to Minnesota Power in its August 12, 2020, joint comments on Minnesota Power's proposed 2021-2023 Conservation Improvement Program

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[281] *Id.* at Section 3.5.
[282] *Id.* at Section 3.5.1.
[283] *Id.* at Figure 12.
[284] *Id.* at Section 3.5.2.
[285] *Id.*
[286] *Id.*

Triennial Plan.[287] While inequities remain in Minnesota Power's approved Triennial Plan,[288] the utility's spending on low-income energy conservation programs (as a percentage of overall energy conservation spending) was the highest among utilities required to submit Triennial Plans at the time. Minnesota Power was the sole utility whose 2021-2023 Triennial Plan met and exceeded the increased low-income minimum spending requirements outlined in the Energy Conservation and Optimization Act of 2021 ("2021 ECO Act") before the Act's passage.[289] This is commendable. The 2021 ECO Act requires that public utilities like Minnesota Power increase minimum spending levels on low-income energy conservation measures from 0.1% to 0.4% of gross operating revenue from residential customers in 2022, and then again to 0.6% in 2024.[290] We will continue to advocate through the Conservation Improvement Program proceedings for Minnesota Power (and all other utilities) to ensure investments in and energy savings from low-income energy conservation programs go beyond meeting statutory minimum requirements and are instead proportional to meeting the needs of under-resourced customers in Minnesota Power's service territory.

With respect to rooftop solar and access to the benefits of distributed solar, PSE found another inequitable situation: less than 5% of rooftop solar adopters in Minnesota are in the lowest-income bracket, while more than 40% are in the highest-income category.[291] While Minnesota

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[287] Minn. Dep't. of Commerce, Joint Comments of Fresh Energy, National Housing Trust (NHT), and Natural Resources Defense Council (NRDC*), In the Matter of Minnesota Power's 2021-2023 Electric Conservation Improvement Program Triennial Plan*, Docket No. E015/CIP-20-476 (Aug. 12, 2020).
[288] As Fresh Energy reiterated in joint comments to the Department of Commerce's proposed decision to approve Minnesota Power's Triennial Plan, submitted with NHT, NRDC, Minnesota Housing Partnership, and the cities of Minneapolis and Saint Paul. *See* Minn. Dep't. of Commerce, Joint Comments, *Staff's Proposed Decisions Regarding 2021-2023 CIP Triennial Plans*, Docket No. E015/CIP-20-476 (Oct. 13, 2020).
[289] The Energy Conservation and Optimization Act of 2021, H.F. 164, 92nd Leg. (Minn. 2021).
[290] Minn. Stat. § 216B.241, subd. 2b(b).
[291] PSE Report at Section 3.5.3.

Power's SolarSense and low-income solar grant programs aim to expand solar adoption, funding is capped and therefore these programs have limited reach. The 2020 extension of SolarSense and expansion of funding for the low-income grant program are positive steps.[292] PSE recommends MP make additional investments in community solar projects that prioritize access for under-resourced customers to reduce electricity costs and disparities in energy burden. CEOs agree with PSE's recommendations.

PSE's assessment of energy access and equity issues in Minnesota Power's plan demonstrates both how such an analysis can be conducted and how to use these insights to inform planning priorities and program design. The analysis PSE conducted, for example, demonstrates the importance of calibrating investment levels to achieve equitable outcomes in key customer cost-saving resources such as energy efficiency and distributed solar.

D. Summary of Report Findings and Implications for this Proceeding.

The PSE report has several conclusions that are important for the Commission's consideration in this proceeding and future IRPs.

1. Minnesotans could see significant public health benefits from earlier retirement dates for the coal and biomass plants in MP's portfolio. Boswell has significant negative health impacts for the region, and Hibbard, though a small source of power, has disproportionately large health impacts. The state could save hundreds of millions of dollars in health costs by closing these facilities earlier than MP plans. Importantly, these health costs fall disproportionately on lower-income communities and native populations in Minnesota – communities that face disproportionate burdens on a range of health and socioeconomic measures as a result of historic and current inequities.

2. NTEC's true climate impacts are more than double its direct CO_2 emissions. It is crucial that Minnesota take upstream methane and methane leakage into account when evaluating the social costs of fossil gas infrastructure.

3. To address disparities in energy burden, and even to prevent exacerbation of current disparities, Minnesota Power must commit to its low-income energy conservation

[292] Minn. Pub. Utils. Comm'n, *In the Matter of Minnesota Power's Petition for Approval of Its New SolarSense Customer Solar Program*, Order Approving Program Extension and Changes, In Part, With Modifications, Docket No. E-015/M-20-607 (Dec. 17, 2020).

programs achieving 33% of overall residential energy savings. Minnesota Power should also increase investments in community solar projects and distributed generation programs that reduce electricity costs and extend clean energy access to a significantly larger number of low-income customers.

4. Resource planning can and should include a robust analysis of the equity implications of potential resource pathways. This report provides one example of how Minnesota utilities' resource planning processes can consider in an empirical way the public health impacts of electricity generation choices, and the geographic and demographic distribution of those impacts.

IX. RECOMMENDATIONS

We respectfully request that the Commission:

A. Modify Minnesota Power's IRP by:
   1. ordering Minnesota Power to withdraw from the NTEC project and revoking the Commission's approval of the related affiliate interest agreements;
   2. ordering retirement of the Hibbard plant in 2023; and
   3. finding the need for approximately 600 MW of solar by 2026.

B. Order the retirement of Boswell 3 by the end of 2029.

C. Order that Minnesota Power:
   1. commence planning the transmission system reliability mitigations needed to maintain the option of retiring the Boswell facility entirely, including unit 4, by no later than 2030; and
   2. submit annual reports to the Commission beginning one year from the date of this order and continuing until the filing of the next IRP. Such reports must:
      i. describe work done to date and work yet to be completed, providing a schedule of expected milestones, and estimating the earliest date for completion of the transmission system reliability mitigations; and
      ii. specifically evaluate converting Boswell 3 to a synchronous condenser upon retirement.

D. Order that Minnesota Power work with stakeholders to include an analysis in the next IRP that identifies the near-term steps needed to ensure Minnesota Power meets its customers' needs in a fashion compatible with 1.5°C pathways.

E. Commence a proceeding to update the estimates of the likely range of costs of future carbon dioxide regulation on electricity generation pursuant to Minn. Stat. § 216H.06 and the rules for their application.

F. Order that Minnesota Power:[293]

1. work with stakeholders to develop a modeling construct that enables Minnesota Power, as part of its next resource plan, to model solar-powered generators connected to the company's distribution grid as a resource. Minnesota Power and stakeholders shall address the following factors in developing the modeling construct:
    i. using a "bundled" approach as is used to model energy efficiency and demand response;
    ii. the costs borne by the utility and the costs borne by the customer;
    iii. cost effectiveness tests; and
    iv. other topics as identified by stakeholders.

2. take steps to better align distribution and resource planning, including:
    i. set the forecasts for distributed energy resources consistently in its resource plan and its Integrated Distribution Plan;
    ii. conduct advanced forecasting to better project the levels of distributed energy resource deployment at a feeder level;
    iii. proactively plan investments in hosting capacity and other necessary system capacity to allow distributed generation and electric vehicle additions consistent with the forecast for distributed energy resources;
    iv. improve non-wires alternatives analysis, including market solicitations for deferral opportunities to make sure Minnesota Power can take advantage of distributed energy resources to address discrete distribution system costs; and
    v. plan for aggregated distributed energy resources to provide system value including energy/capacity during peak hours.

3. account for local clean energy goals, in aggregate, in forecasting and modeling. In particular, the plan should include consideration of local community generation goals for distributed generation in its next IRP.

G. Order that Minnesota Power's next IRP include an analysis of the public health impacts, over the 15-year planning period, of its current generation fleet, its proposed plan, and other resource scenarios studied. The public health analysis should at minimum evaluate and quantify the health costs associated with fine particulate matter from coal and biomass power plants.

[293] Similar language was recently adopted in by the Commission: Minn. Pub. Utils. Comm'n, *In the Matter of the 2020-2034 Upper Midwest Integrated Resource Plan of Northern States Power Company, d/b/a Xcel Energy,* Order Approving Plan with Modifications and Establishing Requirements for Future Filings, Docket No. 19-368 para. 15 (April 15, 2022).

H. Order Minnesota Power to, prior to the next IRP, conduct community outreach and establish a stakeholder group to:[294]
   1. provide input on the public health analysis for the next IRP, including the methodology, results, and implications for Minnesota Power's resource plan;
   2. inform the design of electricity services and programs that improve equitable electricity delivery, improve customer access to energy efficiency and load-shaping programs, and improve customer access to DG and renewable energy. These services and programs should particularly focus on reducing disparities in energy burden, ensuring equitable access to low-income residents, and ensuring equitable access to Black, indigenous, and communities of color that have disproportionately borne costs of unjust and inequitable energy decisions;

I. Order Minnesota Power, in its next IRP docket, and in a separate docket to be established by the Executive Secretary, to file details describing stakeholder outreach and progress on the above requirements in H, (above) by January 1, 2024, and annually thereafter.

Dated: April 28, 2022

/s/Evan Mulholland

Evan Mulholland
Barbara Freese
Stephanie Fitzgerald
Minnesota Center for Environmental Advocacy
1919 University Avenue West, Ste. 515
St. Paul, MN 55101
(651) 223-5969
emulholland@mncenter.org
bfreese@mncenter.org
sfitzgerald@mncenter.or
Attorneys for Clean Energy Organizations

[294] CEOs also relied on the Commission's language in its recent Xcel order for this recommendation. *Id.* para. 25 (Apr. 15, 2022).